Appendices

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Appendix A.

A.1 Introduction

This appendix provides information to support the analysis of fuel cycle emissions from conventional and alternative fuels. The information is organized in the following sections:

A.2 — Fuel Cycle Analysis. Background information and definitions used in this study are included in this section.

A.3 — Definition of Fuel Cycles. For each fuel, the feedstocks, transportation modes, and other parameters that affect fuel cycle emissions are discussed. All of the fuel production pathways considered in this study and the impact of alternative pathways on emissions are identified.

A.4 — Emissions from Fuel Production and Distribution Processes. Emission rates for steps in the fuel cycle are identified with emphasis on emission sources in California. Data sources that determine the speciation of toxic components are described.

A.5 — Local Fuel Cycle Emissions. Fuel cycle emissions in urban areas and the rest of California for NO_x, CO, PM, NMOG, and toxics are identified for each fuel. The emissions are broken down by fuel cycle steps with the goal of differentiating NMOG sources to allow for the determination of toxic components. The effect of fuel economy and fuel cycle emissions is also analyzed.

A.6 — Fuel Production Energy Inputs and Greenhouse Gas Emissions. Energy inputs for each step in the fuel chain are identified. The energy inputs allow for the determination of fuel cycle emissions using a modified GREET model (Wang, GM). GHG assumptions regarding methane and N_2O emissions are documented. The results are presented on a mass of GHG per unit of energy basis.

A.2 Fuel Cycle Analysis

The fuel cycle emissions presented in this report correspond to the impacts of production, transportation, and distribution of fuels to California. The analysis presented here is aimed at identifying marginal emissions associated with large volume fuel distribution. Fuel production processes are categorized into eight production and distribution phases, shown in Table A-1. These phases are grouped into the categories of extraction, production, marketing, and distribution, which are later used for presenting emissions results.

Identifying emissions by spatial location complicates the analysis of fuel-cycle emissions considerably because fuel and feedstock transportation distributes emissions in several of the geographic locations considered in the study.

Table A-1: Fuel-Cycle Emissions Were Categorized into Eight Production and Distribution Phases

Phase No.	Description
Extraction	
1.	Feedstock extraction
2.	Feedstock transportation
Production	
3.	Fuel processing/refining
Marketing	
4.	Fuel storage at processing site
5.	Transport to bulk storage
6.	Bulk storage
7.	Transport to local distribution station
Distribution	
8.	Local station distribution

A.2.1 Geographic Distribution

Because some fuels will be produced outside of California, emissions from the entire fuel-cycle will not directly impact California urban areas. For this reason, it is important to identify the percentage of feedstock extracted or fuel produced in each area. In order to help evaluate the impact on local emission inventories and air quality as well as to take into consideration the differences between local emission rules, the emissions were geographically categorized. Emissions from fuel production can then be allocated according to the locations in Table A-2. This table also shows the acronyms used to identify each of these areas for this report.

Table A-2: Locations of Emissions

Location	Acronym
Within the SoCAB	SoCAB
Within California, but outside the SoCAB	CA
Within the U.S., but outside of California	U.S.
Rest of the World, outside the U.S.	ROW

SoCAB = South Coast Air Basin.

Emissions for fuel or feedstock transportation and distribution are also divided into the four geographic distribution categories. For example, emissions for ships entering and exiting the San Pedro ports were attributed to the SoCAB for a portion of the trip. The balance of these emissions was attributed to the rest of the world. Both land and sea transport emissions were allocated proportionally according to their transport route.

The timeframe for the analysis is beyond the year 2010 and corresponds to scenarios for a growing demand for gasoline. By the year 2020, baseline gasoline demand will be 19 billion gallons per year, according to the Task 3 report (CEC 2002). With the most aggressive petroleum reduction strategies analyzed by the Energy Commission, gasoline demand would drop to 12 billion gallons per year. This consumption level plus demand from Nevada and Arizona would be sufficient to keep California refineries operating at capacity.

A.2.2 Marginal Emission

This study is intended to be used to evaluate marginal emissions from fuel production. The interpretation of which emissions correspond to marginal fuel production depends on several factors that are discussed in the following section. The focus on marginal emissions raises questions of transporting emissions into and out of the state. For example, methanol could be sold for vehicle use in the SoCAB without any production emissions affecting local air quality. Similarly, gasoline is transported to other states from the SoCAB, while the refinery emissions contribute to emission inventories in the SoCAB.

Some environmental groups and researchers consider the marginal analysis in this study to provide optimistic results. Indeed, the marginal emissions are lower than average emissions. However, both electric and liquid fueled technologies are being compared on a marginal basis. In the author's view, marginal emissions represent the contribution to the air that the breathers breathe. Only substantial changes in the environmental and economic structure of fuels would result in emissions equal to the average emissions from refineries. For example, if new refineries were to be built in California or capacity were increased beyond currently permitted levels, the contribution to air emissions on the margin would need to be reexamined. In principle, new petroleum refineries could be constructed in California and emission offsets could be obtained. The use of new fuels, such as reformulated diesel, for PZEV vehicles in California would not trigger such infrastructure changes.

The emphasis on marginal emissions by industry groups was a key outcome of the 1996 ARB Fuel Cycle study. Industry groups and State agencies ultimately agreed that a marginal approach was relevant in the context of a moderate usage of alternative fuels. Another point of view is that a very substantial use of alternative fuels could result in a reduction in refinery capacity. Given the limited refinery capacity and growth in gasoline demand, this outcome is unforeseen.

The emission impact of displacing a very large fraction of refinery capacity with alternative fuels is not analyzed here. Even if such a scenario were to occur, it is uncertain that average emission rates would accurately reflect the impact on emissions as the disposition of emission permits and offsets would need to be taken into account.

In the early 1990s California policy makers incorporated the "zero emission vehicles" into attainment goals for air quality. Public discussion at the time raised the point that some vehicles which have no emissions "at the tailpipe" (e.g., battery-powered vehicles that have no tailpipe) nonetheless were not "zero emission" because their ultimate source of power, such as an electric generating plant, created its own fuel cycle pollution.

Methodologies were very quickly developed by stakeholders to try to quantify the "total emissions" of a vehicle on a grams-per-mile basis. Very quickly, perplexing issues developed. If a battery is charged from a power plant in Los Angeles, the comparison with a gasoline vehicle is very straightforward. But if Los Angeles is consuming a generic mix of electricity from a power grid supplied by several states, then emissions generated out-of-state might not be relevant to considering local attainment goals. There is no way to know if electric vehicles are drawing their power from out-of-state or from within the attainment area. One way to cope with this problem is to subtract out-of-state upstream pollution from the grams-per-mile calculations. These seemingly arcane considerations can have substantive impacts on the grams-per-mile figure that is used as an index in policy making. They therefore can have considerable importance.

The principle of fuel cycle emissions is easy to grasp, but in practice these quantification exercises are quite complicated. Some stakeholders argued that if electric vehicle emissions were to be quantified with regard to their "fuel cycle emissions," then gasoline-powered vehicles, which have traditionally been regulated "at the tailpipe," should also be subjected to the same methodology. But "fuel cycle emissions" quantification for a gasoline vehicle has as many sources of potential variation as vehicles that charge off a regional power grid. Indeed, virtually every known conventional or alternative fuel technology (i.e., gasoline, diesel, CNG, electric, electric hybrid, methanol, etc.) poses a considerable quantification challenge when the "full fuel cycle" is taken into account.

The question of "where California gets its fuel" is important to the full fuel cycle emissions quantification. Under procedures similar to those used for quantifying electric vehicle upstream emissions, California gasoline and diesel fuel brought in from abroad should not have refinery emissions included in its "grams per mile" tally. However, imported refined products would be subject to various alternative quantification methods relating to offloading at port, spillage, evaporation, and distribution.

Rest-of-the-World: Foreign Imports of CA-RFG

During the gasoline price spike of 1997 modest downward pressure on California's market was exerted by contracts for CA-RFG from such distant sources as Finland (Neste, a company that primarily exports for world markets), the Caribbean (Amerada Hess), and Asia. California's "imports" of refined product are currently about 5% of the market, but does not come from foreign suppliers. CA-RFG makes its way into some of the more difficult-to-reach parts of Northern California from refineries in the Midwest.

Most large-scale sophisticated refineries in the U.S. and worldwide have the ability to make CA-RFG. They do not face the significant engineering problems faced by the California refineries. The California- specific problems stem from the need to make the entire spectrum of refinery products conform to strict environmental standards. The more volatile lighter aromatics must be reduced, broken down, or otherwise eliminated from the production process.

Many foreign refiners face no such restriction. They can respond to high prices in California by running batches of CA-RFG and putting many of the undesirable components, which they have removed from the CA-RFG, into their other fuels. A typical world-class refinery could in theory produce as much of 20% of its output as CA-RFG. Because they face few or no local fuel content regulations, they can run off a premium grade environmental gasoline by diverting unwanted elements into an increased-volatility gasoline.

In theory, therefore, a number of foreign refineries can "skim" the California market during high price episodes. In practice, this is difficult and risky, because sometimes the California-bound product reaches its destination after the price spike has passed. Neste has testified that trying to enter the California market during a refinery or equipment-related price spike is extremely risky and has not been particularly profitable in the past.

Nonetheless, were a sustained price increase to occur in California, some of these refineries might find systematic participation in the California market to be attractive. The specific form of market intervention cannot be ascertained. Such foreign suppliers might simply try to act as spot suppliers to the market. More likely, they would seek long-term contracts with major California companies. Alternatively, major California companies might approach them for additional product. The California companies could even buy participation in selected foreign operations to forge a closer relationship for long-term supply purposes.

The ability of out-of-state refiners to make up to 20 percent CA-RFG may raise a policy question of fairness. Is California in effect using its wealth to "export" pollution by inciting refiners to ship an environmental premium grade to the state, while a more volatile product was marketed elsewhere? The question cannot be answered from general principles. If, for example, it were certain that the less-desirable product stream was being marketed in notorious high-pollution cities, for example, the implications would be troubling. But the less desirable product could also be marketed at a discount and used in agricultural or other commercial applications in countries with few pollution problems. This might actually help their economies while doing no or limited environmental harm.

The production of increased-volatility product as a corollary of producing CA-RFG could well be a short- to medium-term occurrence. It might resurface occasionally during price spikes caused by malfunctions in refineries or the distribution network. In the long-term, the emergence of large-scale markets where environmental regulations are in effect, such as in the United States and Western Europe, makes it likely that worldwide some "designer refineries" will specialize in "boutique gasoline" to meet the needs of countries or areas that have enacted stringent fuel requirements. There is already some concern in Arizona, for example, that CA-RFG does not meet the specific attainment goals of Phoenix and Tucson.

Other refineries will continue to produce in more traditional ways. This already is the case: tetraethyl lead is still in use in much of the world, even though it has been banned from American markets and is being phased out of Europe.

The rest-of-the-world permutations would therefore look something like this:

A. Incremental and more frequent participation of foreign refiners in CA markets, implying a gradually increasing flow of foreign refined imports in California's total fuel mix. In the early phases these foreign refiners would be marketing CA-RFG as a premium export grade and simultaneously making a lower-grade fuel to less stringently regulated markets.

B. The emergence of "designer refineries" tailored specifically to the needs of markets that have enacted stringent environmental requirements. Conventional refineries not adhering to these production practices would produce environmental premium grades only on an occasional basis in response to specific price spikes. Several of the people interviewed for this report suggested that the spread of CA-RFG and other "green" fuel formulations is an industry-wild card possibility that could have the effect of making CA-RFG more available, nationally and internationally, than has been the case until now.

These permutations are also compatible with the participation of Texas in the California market.

Three additional points should be mentioned in this section. First, policy makers may have concerns about the equity issue associated with the marketing, elsewhere in the world, of a "lower-grade gasoline" that is a by-product of making CA-RFG. This concern might make them lean toward expediting or expanding permitting for in-state refining. Second, Caribbean ethanol producers are completely exempted from U.S. tariffs that apply to other world ethanol producers (Mexico and Canada have special, lower tariffs on ethanol). This tariff exemption raises the possibility that Caribbean refineries will play a role in market scenarios where the MTBE phase-out results in increased ethanol use. Third, from the point of view of emissions quantification, permutations that envision increased foreign imports will have associated emissions from increased docking and unloading activities.

Puget Sound Refineries

The Puget Sound refinery operations (Shell at Anacortes, ARCO at Cherry Point) have recently been able to participate in the production of CA-RFG. Regardless of whether their feedstock comes from Alaska or Asia, these refineries are part of a regional air-inventory that is more forgiving than California's, and one person interviewed considered it much easier to get permitting to expand production in these areas than in California. These refiners are already attracted to a limited degree, to the higher priced California market. Expanding their production capability, as with the Gulf Coast, could prove an attractive option to increase long-term supplies of fuel.

Expansion of California Refining

The Western States Petroleum Association (WSPA) has circulated an op-ed article that calls for "modernizing [petroleum fuels] infrastructure to make it more efficient," the need to favor large scale investments, and the need to expedite the siting, permitting and construction of "plants, pipeline terminals, and service stations."

This general text is consistent with the various options already discussed above. In an interview, the author suggested that in-state expansion of refining will be the single biggest source of CA-RFG in the years to come. Almost all other options, in his view, presented significant cost disadvantages relative to what the California refineries could do within the "footprint" of their existing physical plant. California refineries would process increasing crude imports (whether from abroad, or from the Gulf Coast, or other sources).

This would be possible because a "regulatory bubble" over refining operations allows trading of reductions from older types of equipment to operations designed to increase throughput. Though the specific details were not discussed, there are apparently a number of technological advances of the past five to ten years that suggest major control opportunities. The author also felt that the regulatory authorities would be amenable to equipment upgrades. In a nutshell, CA refining should be able to meet increasing levels of demand with constant or even declining total emissions.

Assumption for California Gasoline Supply

Since the baseline scenario in the Energy Commission's study of petroleum reduction options is a steady growth in demand climbing to over 30 billion gallons of demand by 2050, it seems prudent to assign most of the emissions associated with reductions in petroleum usage to a reduction in imports. A modest amount of expansion in California refinery capacity is expected to occur but only the most aggressive petroleum reduction options would result in this capacity not being fully utilized. Demand from Nevada and Arizona would also provide a market for California refineries. Therefore, for the demand assumptions developed in the Task 3 report, refinery output and corresponding emissions will not be affected by a reduction in fuel usage.

A.2.3 Fuel Properties

The fuel vapor pressure and molecular weights are shown in Table A-3 below. These properties are important in determining hydrocarbon emissions from storage and transport of these liquid fuels.

Table A-3: Vapor properties for liquid fuels

Fuel	Gasoline	Diesel	FT Diesel	E100	M100
RVP (psi)	6.80	0.022	0.030	2.3	4.63
TVP (psi)	6.10	0.015	0.02	1.7	3.50
Temperature (°F)/ (°C)	90/32	90/32	90/32	90/32	90/32
Vapor MW (g/mol)	76	130	120	46	32

Source: A. D. Little. Discussion of heating values, feedstocks to be completed.

A.3 Definition of Fuel Cycles

This section of the appendix discusses the fuel cycles for each of the fuels and feedstocks considered in the study. The fuel cycles include the eight production and transportation phases indicated earlier in Table A-1.

A.3.1 Petroleum Fuels

A.3.1.1 Crude Oil Extraction and Transport

A significant fraction of crude oil is produced in the SoCAB, and marginal emissions associated with oil production in the SoCAB are estimated to be near zero. Refineries in the SoCAB operate at capacity, and demand for additional gasoline and diesel could be met by importing additional finished fuels. Oil production is estimated to not change with additional demand for diesel or gasoline fuels, as additional product may be imported to California or refinery operations may be modified.

Changes in fuel demand will not shift the mix of crude oil sources used in California. The mix of crude oil could change with changing oil prices. If oil prices dropped substantially, for example, more costly oil production in California could be reduced. Crude oil production techniques depend on the demand for oil. Increased use of more energy intensive techniques such as enhanced oil recovery would correspond to higher petroleum prices. The trend in California is to extract more oil through thermally enhanced oil recovery. This report does not attempt to analyze the effect of changes in California oil production.

Oil is transported to the refineries using two primary methods: pipelines and tanker ships. Pipeline emissions result from the pumps that move the oil through the pipelines. Tanker ship emissions are produced by the propulsion and auxiliary engines, which operate on heavy fuel oil. Table A-4 shows transportation modes that were estimated for petroleum feedstocks and products.

Table A-4: Petroleum Transport

Transport Process	Location	One Way Distance (mi)
Crude oil pipeline	Singapore (ROW)	200
Gasoline and diesel Product tanker	Singapore (ROW)	7,650
	CA Coast (SC)	26

A.3.1.2 Oil Refining

A variety of fuels are produced by oil refineries in the SoCAB. Products from refineries include several grades of gasoline, diesel, kerosene (jet fuel, heating oil, No. 1 Diesel), LPG, heavy oil, petroleum coke, sulfur, and asphalt. Energy inputs to refineries include crude oil, electric power, natural gas, gasoline blending stocks such as alkylate (high octane components such as iso-octane), and oxygenated compounds such as methanol, MTBE, and ethanol. The specifications for fuel in California have been changing over the years with sulfur reductions in diesel, reformulations of gasoline, low aromatics and equivalent diesel, and reductions in the use of MTBE. At the same time, emissions from refineries in the SoCAB have been declining steadily. The combination of feedstocks, products, and emissions makes allocating emissions to refinery products difficult.

It is unlikely that new refineries will be built in California. In fact, from 1985 to 1995, ten California refineries closed, resulting in a 20 percent reduction in refining capacity. Further refinery closures are expected for small refineries with capacities of less than 50,000 bbl/day. The cost of complying with environmental regulations and low product prices will continue to make it difficult to continue operating older, less efficient refineries.

To comply with federal and state regulations, California refiners have invested approximately $5.8 billion to upgrade their facilities to produce cleaner fuels, including reformulated gasoline and low-sulfur diesel fuel. These upgrades have received permits since low-sulfur diesel fuel regulations went into effect in 1993. Requirements to produce federal reformulated gasoline took effect at the beginning of 1995, and more stringent state requirements for ARB reformulated gasoline went into effect statewide on June 1, 1996.

As a first order estimate, there are no marginal emissions associated with producing more conventional diesel, gasoline, or LPG in a refinery. Several possibilities exist for adjusting refinery operation for changes in fuel output. If gasoline demand were reduced, it is likely that imports of finished gasoline would simply be reduced. Increased diesel demand at the expense of gasoline sales could be met by increasing the mix of diesel products that are imported to the SoCAB or by adjusting refinery operations to produce more diesel. Analyzing the effect of changing the shift in refinery products ideally would be accomplished by a linear programming (LP) model that optimizes all of the refinery streams for an optimal economic and fuel specification output. Such LP analyses primarily are aimed at analyzing the effect of different fuel formulations or refinery process configurations.

Emissions from oil production in the SoCAB are expected to decrease over the next 20 years with the following measures:

- NO_x controls on refinery fluid catalytic cracking units
- Emission controls on off shore oil production
- Emission controls from refinery flares
- Carbon absorption, refrigeration, and incineration of fugitive hydrocarbons
- Emissions controls from bulk terminals

A.3.1.3 Gasoline and Diesel Storage and Distribution

After diesel and gasoline are produced in a refinery, they are stored in bulk tanks and distributed to fueling stations in tank trucks. Emissions resulting from the storage of petroleum and petroleum fuels consist of two main types: fugitive and spillage emissions. Fugitive emissions are hydrocarbon emissions that escape from storage tanks, pipes, values, and other sources of leaks. These emissions are generally greater for gasoline than diesel, due to its higher vapor pressure.

The low vapor pressure of diesel has generally resulted in limited requirements on vapor recovery from storage and fueling equipment. The vapor pressure from diesel is so much lower than that of gasoline, that the uncontrolled diesel vapor losses are less than 10 percent of gasoline emissions with 95 percent emission control.

Vapor losses primarily occur when tank trucks are filled at the bulk terminal, unloaded at the fueling station, and during vehicle fueling. Spillage during vehicle fueling is also a significant source of emissions.

A.3.1.4 LPG Storage and Distribution

The fuel-cycle steps for LPG parallel those for gasoline and diesel. Petroleum-based LPG would be produced from refineries in the SoCAB. LPG is refined, stored, and distributed as indicated in Table A-5.

Table A-5: LPG from Crude Oil-Production and Distribution Phases

Phase	Process	Emission Sources	Marginal Emissions[a] NO_x	Marginal Emissions[a] NMOG
1	Extraction	Heaters, pumps, fugitive	—	—
2	Transport	Pipeline (pumps), ships (engines)	M	M
3	Refining	Refining process emissions	—	M
4	Site storage	Refinery tanks	0	M
5	Transport to bulk storage	Tanker truck	M	M
6	Bulk storage	Pressurized tanks	0	M
7	Transport to local station	Tanker trucks (engines & fugitive)	M	M
8	Local station distribution	Above ground tanks	0	M

[a] M indicates if marginal emissions occur in the SoCAB. — indicates no marginal emissions, while zero emission sources are indicated with a 0.

A.3.2 Natural Gas Based Fuels

Several of the fuels considered in the study are produced from natural gas. These include methanol, synthetic diesel, LPG, LNG, CNG, and hydrogen. The fuel cycles of these fuels are briefly described below. Several fuel cycle studies have looked at each of these fuels separately and should be consulted for more information (ARB 1996, ARB 2001, GM).

Synthetic Diesel Production from Natural Gas

Synthetic fuels can be produced from the catalytic reaction of CO and hydrogen. The Fisher Tropsch (FT) Process is one process that has been developed for fuel production. In recent years, developments in catalysts have allowed for the production of fuels in the diesel boiling point range. Synthetic diesel and FT Diesel are categorized together as all approaches for producing synthetic diesel are conceptually similar and result in the same emissions impact in California.

The FT Process was originally developed in Germany in the 1920s to produce diesel from coal. FT plants are also operating in South Africa and Russia to make synthetic gasoline from coal. The FT Process has three principal steps. First, a feedstock must be converted to synthesis gas, a mixture of carbon monoxide and hydrogen. Potential feedstocks include coal, biomass, and natural gas. A catalytic reactor converts the synthesis gas to hydrocarbons in the second step. The mixture of hydrocarbons consists of light hydrocarbons and heavier waxes. The majority of the hydrocarbons are saturated. In the third step, the mixture of hydrocarbons is converted to final products such as synthetic diesel fuel.

The FT Process consists of three conversions:

1. Feedstock to a synthesis gas, a mixture of CO and hydrogen
2. Synthesis gas to hydrocarbons by use of a catalytic reactor

3. Hydrocarbons to the final products, like synthetic diesel

Currently FT plants are being constructed to use remote natural gas as a feed stock. FT fuels potentially can be produced from renewable sources such as biomass.

FT diesel fuel can be transported in conventional product tankers. Bulk storage, product blending, truck delivery, and local product dispensing can be accomplished with existing infrastructure. If pure FT diesel fuel is sold as a separate product, refueling stations will need to reallocate their inventory of local storage tanks or install additional storage and dispensing equipment.

FT diesel is likely compatible with existing dispensing equipment and vehicle fuel systems. However, fuel compatibility issues have not been widely documented. Some fuel compatibility problems were identified when low aromatics diesel fuels were introduced in California. Problems appeared to occur on older model diesel engines with a specific type of fuel system.

Major oil companies are supporting the development of FT fuels or gas-to-liquids (GTL) products. Shell, Exxon, ChevronTexaco, and ARCO have built or are planning to build production facilities. Oil companies own many of the natural gas fields in the world and are interested in finding a market for the fuel. Exxon included an article describing its GTL technology in their 1998 publication for shareholders which illustrates their interest in the technology (Weeden, GTL Progress, 2001).

FT fuels are attractive to oil companies since they improve the quality of diesel and make use of their natural gas resources. These fuels are also attractive since they can be used in existing vehicles.

FT fuels will become more widely available as more facilities are constructed to take advantage of low cost remote natural gas. The growth of the market may depend on the price of oil. Since the cost of producing FT fuels does not drop significantly with a drop in the price of oil, low oil prices have hindered the commercial production of FT diesel. FT fuels will likely be blended to produce high cetane, low aromatic diesel before they are sold as pure clean fuel alternatives. The blending approach allows for a build up of production and bulk storage capacity. If a demand for pure FT fuels develops, the infrastructure will be in place.

Methanol Production from Natural Gas

Most methanol in the world and all of the methanol used in California as a vehicle fuel is made from natural gas. The conversion process typically used, called steam reforming, is similar to the process used to make synthetic diesel, but uses different catalysts, temperatures, and pressures. The upstream fuel cycle is similar to compressed natural gas. Fuel distribution for methanol consists of bulk storage terminals and transfer systems similar to those for gasoline. The steps for methanol production and distribution are shown in Table A-6.

Table A-6: Methanol from Natural Gas-Production and Distribution Phases

Phase	Process	Emission Sources	Marginal Emissions[a] NOx	NMOG
1	Extraction	Compressors, fugitive	—	—
2	Transport	Natural gas pipeline (compressors & fugitive)	—	—
3	Production	Fugitive emissions, vent gas combustion	—	—
4	Site storage	Fixed roof tanks	—	—
5	Transport to bulk storage	Pipeline (pumps & fugitive)	M	M
6	Bulk storage	Floating roof tanks	0	M
7	Transport to local station	Tanker trucks (engines & fugitive)	M	M
8	Local station distribution	Underground tanks, refueling vapors and spillage	0	M

[a] M indicates if marginal emissions occur in the SoCAB. — indicates no marginal emissions, while zero emission sources are indicated with a 0.

A.3.2.1 Fuels from North American Natural Gas

Compressed Natural Gas (CNG)

Natural gas is available throughout most of California for home heating and industrial energy uses. The infrastructure for the extraction, processing, and distribution of natural gas is available for most potential CNG users where a compression facility might be installed. The gas is then transported to California in pipelines where it is distributed to the local user. The pressure of the gas at the local user has the most significant impact on the energy required for gas compression.

Slow fill (or time fill) systems compress the gas and directly fill the vehicle over an extended period of time (usually overnight). The compressor output is only slightly higher than the vehicle storage pressure. Compression is accomplished isothermally since the compressed gas has time to equilibrate with the ambient air temperature.

Fast fill fueling requires slightly more energy. The gas is compressed and stored in a cascade of storage cylinders, or a large capacity compressor produces a flow rate high enough to fill the vehicle in about 10 minutes. The cascade storage pressure or compressor output is about 3600 psi for a 3000 psi vehicle storage system. Also, fast fill fueling results in rapid compression and corresponding temperature rise of the gas in the vehicle. If the vehicle is fueled to 3000 psi, its final fill pressure will drop after the temperature in the vehicle tank equilibrates with ambient air. Sophisticated fueling systems that compensate for the ambient temperature and gas with the vehicle have been designed. Such systems would allow the vehicle to be filled to an effective pressure of 3000 psi. Therefore, after compression to 3600 psi and the fuel heating effect are taken into account, fast fill fueling requires about 22 percent more energy than that of slow fill fueling.

Table A-7 shows the scenarios for CNG production and distribution.

Table A-7: Natural Gas-based Gaseous Fuels Production and Distribution Phases

Phase	Process	Emission Sources	Marginal Emissions[b] NO$_x$	Marginal Emissions[b] NMOG
1	Extraction	Compressors, fugitive	—	—
2	Transport	Natural gas pipeline (compressors and fugitive)	—	—
3	Refining	Fugitive emissions, vent gas combustion	—	—
4	Site Storage	None	—	—
5	Transport to bulk storage	Pipeline (pumps and fugitive)	M	M
6	Bulk storage	Underground storage	—	—
7	Transport to local station	Pipeline (pumps and fugitive)	M	M
8	Local station compression reforming	Refueling losses, electric power for compression, reformer emissions	M	M

[a] M indicates if marginal emissions occur in the SoCAB. — indicates no marginal emissions, while zero emission sources are indicated with a 0.

Liquefied Natural Gas (LNG)

Table A-8 shows the assumptions for LNG production and distribution. Extraction and clean up for LNG were considered to be the same as that for CNG. Differences between CNG and LNG production arise from the geographic location of the natural gas supply. Currently, a substantial portion of the LNG supplied in the U.S. is obtained from overseas via LNG tankers.

Table A-8: Production and Distribution Phases for Rail-Transported Fuels[a]

Phase	Process	Emission Sources	Marginal Emissions[b] NO$_x$	Marginal Emissions[b] NMOG
1	Extraction	Compressors, fugitive	—	—
2	Transport	Pipeline (compressors and fugitive)	—	—
3	Refining/Production	Fugitives, compressor engines, gas combustion	—	—
4	Site Storage	Onsite tanks	—	—
5	Transport to bulk storage	Rail car (engines and fugitives)	M	M
6	Bulk storage	Cryogenic tank	0	M
7	Transport to local station	Tanker trucks (engines and fugitive)	M	M
8	Local station distribution	Above grounds tanks, refueling vapors	0	M

[a] M indicates if marginal emissions occur in the SoCAB. — indicates no marginal emissions, while zero emission sources are indicated with a 0.

LNG is produced from natural gas in liquefaction facilities. Natural gas is compressed and cooled and expanded in a multi stage operation. Energy for compression is usually provided with natural gas powered engines. LNG is stored as a cryogenic liquid in insulated storage vessels. The fuel is generally a liquid at its boiling point. When stored close to atmospheric pressure the LNG temperature is -260°C. LNG tanks allow some heat to enter which boils off some liquid to gas. The pressure in the tank increases and after several days, the gas must be vented. The gas can be vented to the atmosphere, recovered as CNG, or burned to generate heat. LNG absorbs heat during transfer operations and some liquid is vaporized. Tank truck fuel transfer to a storage facility usually involves passing a small amount of LNG into a heat exchanger to generate gaseous natural gas. This process increases the pressure in the tank truck and forces the liquid into the receiver tank. After transferring the vapors, the gas on the truck is purged.

Currently, almost all LNG used in vehicle demonstrations has been trucked from Wyoming. Liquefied methane is available from a facility near Sacramento but this resource has not been utilized frequently. The LNG from Wyoming is produced in a pressure let-down facility that requires little energy input for liquefaction. For large scale production the liquefier could be at a natural gas peak shaving facility or it could be built as a dedicated facility. It is unlikely that liquefaction facilities will be built in the South Coast Air Basin. The natural gas will more likely be processed nearby. The energy inputs for LNG production will depend on the integration with pipeline pressure requirements. This study assumes that LNG is imported to the SoCAB by rail, with the calculations based on the Western U.S. An LNG terminal could also be built in Mexico where the fuel could also be distributed by rail to Southern California. Some LNG could also be produced from pressure let-down facilities and in-state production. The primary parameter that affects local emissions is the amount transportation distance.

Most of large scale LNG distribution modes would involve rail transport so their local emissions impact would be similar. GHG emissions are affected by the energy input for natural gas extraction and liquefaction as well as the energy requirements for transportation. Energy requirements and associated GHG impacts for rail transport from the western states are similar to energy requirements for tanker ship transport from remote sources. This comparison can be seen in the discussion of GHG emissions and energy inputs. Another parameter that affects LNG production is the source of energy for liquefaction. As LNG is produced in a location where natural gas is plentiful, natural gas ICE engines are assumed to be the energy source for liquefaction.

Hydrogen

Hydrogen can be produced from the thermochemical processing of carbonaceous materials and the decomposition of water. Most hydrogen today is produced from fossil fuels. Methane, for example, is reformed into CO and hydrogen. The CO is reacted with steam to form additional hydrogen. Non fossil methods of hydrogen reduction include electrolysis of water, thermochemical splitting of water, and photolysis.

Electrolysis separates water into hydrogen and oxygen by passing current through an electrochemical cell. The gaseous hydrogen obtained from electrolysis is over 99.9 percent pure, compared to 98 percent purity for fossil-fuel derived hydrogen.

Table A-9 shows the production and distribution pathway for onsite hydrogen production from natural gas.

Table A-9: Hydrogen from Natural Gas Fuel Production and Distribution Phases

			Marginal Emissions[b]	
Phase	**Process**	**Emission Sources**	**NO_x**	**NMOG**
1	Extraction	Compressors, fugitive	—	—
2	Transport	Natural gas pipeline (compressors and fugitive)	—	—
3	Refining	Fugitive emissions, vent gas combustion	—	—
4	Site Storage	None	—	—
5	Transport to bulk storage	Pipeline (pumps and fugitive)	M	M
6	Bulk storage	Underground storage	—	—
7	Transport to local station	Pipeline (pumps and fugitive)	M	M
8	Local station compression reforming	Refueling losses, electric power for compression, reformer emissions	M	M

[a] M indicates if marginal emissions occur in the SoCAB. — indicates no marginal emissions, while zero emission sources are indicated with a 0.

Distributing hydrogen is difficult because pipelines are not currently available for transporting hydrogen. Existing natural gas pipelines will not be available for hydrogen transport by the year 2010, nor will the hydrogen demand be large enough to support the use of these pipelines. Several compressed hydrogen distribution options are possible. One is storage and dispensing at the hydrogen production facility. This option is only viable for a small vehicle fleet. Other means of distributing compressed hydrogen are possible but were not evaluated further. These include transporting the hydrogen from production facilities to local storage and dispensing stations by tube trailers. Hydrogen is currently available in tube trailers that carry 130,000 scf at 5,000 psi. The hydrogen would be compressed to 6,000 psi for storage at the vehicle fueling station. This option is currently feasible but not very desirable since the amount of hydrogen energy contained in a trailer is lower than that of other fuels.

ADL evaluated the energy inputs for a variety of hydrogen production pathways as part of a study for DOE (DOE 2002). The results of this study can provide a further basis for assessing local emission impacts associated with hydrogen distribution. The on-site steam reformer pathway was selected because it appears to be the lowest cost option in the near term. However, the cost effectiveness of hydrogen production options depends upon many parameters including feedstock price and the usage rate at the fueling facility.

A.3.3 Biomass Fuels

Ethanol

Biomass fuels can be produced from various types of biomass. Ethanol, in particular, has several feedstock options including corn, sugar beets, sugar cane, agricultural residues, and forest materials. The first three feedstocks are starch-based while the latter feedstocks are cellulosic. In this analysis, fuel cycle emissions in the SoCAB are the same for different feedstocks because the fuel is produced outside of the region and therefore only transportation of the fuel creates emissions. Greenhouse gas emissions from different feedstocks, however, are accounted for separately since GHGs are measured globally rather than locally. One option is ethanol produced from the hydrolysis and fermentation of cellulosic biomass in California. The biomass feedstock is assumed to be wood materials, either from forest, agricultural or municipal residues. For California production, a 2000 Energy Commission study of Costs and Benefits of a Biomass-to-Ethanol Production Industry in California found three main elements of the industry: biomass handling (harvesting, processing, storage, and transportation), production of ethanol, and transportation of ethanol. These three elements of the costs analysis are also the same phases for an emissions analysis. In this fuel cycle study, all of the criteria emission impacts occur outside of the SoCAB except transportation of ethanol (Table A-10).

Table A-10: Production and Distribution Phases for Ethanol from Biomass Fuels

Phase	Process	Emission Sources	Marginal Emissions[a] NO_x	Marginal Emissions[a] NMOG
1	Extraction	Agricultural equipment	—	—
2	Transport	Truck (engine)	—	—
3	Refining/Production	Fugitives, gas combustion	—	—
4	Site Storage	Onsite tanks	—	—
5	Transport to bulk storage	Rail car (engines and fugitives)	M	M
6	Bulk storage	Floating roof tank (ethanol), blend with gasoline	0	M
7	Transport to local station	Tanker trucks (engines and fugitive)	M	M
8	Local station distribution	Above grounds tanks, refueling vapors	0	M

[a] M indicates if marginal emissions occur in the SoCAB. — indicates no marginal emissions, while zero emission sources are indicated with a 0.

The other option is the use of corn-based ethanol from the mid-west United States, which is then transported to California by rail or marine vessel.

According to the 2000 Energy Commission Ethanol Cost and Benefit study, ethanol in the U.S. is used in several markets (Perez 2001). Currently, most ethanol is being used in a 10 percent blend with gasoline. This is traditionally referred to as gasohol, a term that is being replaced with ethanol/gasoline blend or E10. Lower percentage blends, containing 5.7 percent of 7.7 percent ethanol are also being used in some areas to conform to air quality regulations affecting the oxygen content of reformulated gasoline. The 5.7 percent blend is California's formulation used to meet a 2 percent by weight federal oxygenate requirement in Phase 3 gasoline. This formulation will be the primary demand for ethanol fuel in California. Additionally, ethanol is used in other motor fuel applications, such as E85 for flexible fuel vehicles, E100 for demonstration in modified heavy-duty fleets or fuel cell-powered vehicles, and Oxydiesel, a blend of 80 percent diesel, 10 percent ethanol, and 10 percent additives and blending agents. The Oxydiesel is also being demonstrated in bus fleets with unmodified diesel engines.

Biodiesel

To be completed.

A.3.4 Power Generation

Electricity in California can be used in the fuel cycle process for powering electric vehicles and electrolysis for fuel cell vehicles operating on hydrogen. The emissions associated with these fuel cycles are entirely associated with the fuel feedstocks and the efficiency of the conversions.

A.3.4.1 Applications for EVs and electrolysis

In the case of EVs, batteries on board the vehicles are charged from electricity on the grid. For fuel cell vehicles, the electricity is used to hydrolyze water, generating hydrogen. Electricity is then used to pump and compress the hydrogen in on-board storage tanks. The hydrogen is then converted to electricity in a fuel cell for operation of the vehicle motor. The fuel cycle emissions for the EV depend on the energy per mile required by the vehicle to operate and the emissions generated per unit of electrical energy generated and transmitted. There are losses during the vehicle charging but since EV energy consumption is reported in terms of kWh of electricity at the outlet, the energy consumption includes charging losses. For the fuel cell vehicle, the fuel cycle emissions depend on the mass of hydrogen per mile required, the energy required for electrolysis and compression, and the emissions generated per unit of electrical energy.

A.3.4.2 Power Generation Resources

The emissions associated with electricity generation have been documented in other studies (ARB 2001). The 2001 ARB study found that modeling power generation and source mix is complex because current generation statistics have little bearing on marginal power generation. Electricity in California is currently generated from a mix of natural gas, hydroelectric power, coal, nuclear power, biomass, and other renewables.

Marginal electricity, however, will not be produced from the same mix of resources or types of power generation facilities. In addition to limited hydroelectric and nuclear capacity, one reason for the difference is that EV charging is expected to occur largely at night. Utilities will incentivize this nighttime charging in order to shift loads to off-peak hours. As a result, a variety of generation resources could be available to meet marginal EV demand. Hydrogen can also be produced off-peak and stored.

The assumptions for the fuel cycle emissions take into account several analyses and models. Different EV charging scenarios have been considered and are based on percentage of off-peak and on-peak charging. The power generation was analyzed using three principal approaches, as indicated in Table A-11.

Table A-11: Methods for Analyzing Power Generation

Method	Analysis Tool	Analysis Date	Scope
CA Dispatch model	Multisym™/RAM	September 1999	Marginal 2010 generation, 95/5 mix
CA Dispatch model	ELFIN	June 1995	Marginal 2010 generation, 95/5 mix Marginal 2010 generation, 80/20 mix Average 2000 generation
Assume new plants	Heat rate data	January 2001	Heat rate for new natural gas generation
Supply Curve	Multisym™ Data	April 2001	Supply and load curve for SCE region, 2003 generation mix

Source: Arthur D. Little.

There may be marginal emissions in the SoCAB due to new gas-fired power plants but the NO_x emissions will be zero due to RECLAIM constraints. CO and NMOG are not governed by RECLAIM. The production and distribution emission sources for electricity are indicated in Table A-12.

Table A-12: Electricity Production and Distribution Phases[a]

Phase	Process	Emission Sources	Marginal Emissions[b] NO_x	Marginal Emissions[b] NMOG
1	Extraction	Compressors, fugitive	—	—
2	Transport	Natural gas pipeline (compressors and fugitive)	M	M
3	Production	Fugitive emissions, combustion emissions	0	M
4	Site storage	—	0	0
5	Transport to bulk storage	Transmission line losses	0	0
6	Bulk storage	—	—	—
7	Transport to local station	—	—	—
8	Local station distribution	Distribution, lines, substation transformers, electrolyzer for hydrogen	0	0

[a] Electricity for battery EVs and hydrogen from electrolysis.
[b] M indicates if marginal emissions occur in the SoCAB. — indicates no marginal emissions, while zero emission sources are indicated with a 0.

Additional emissions from electricity distribution should also be accounted for in the analysis. Typical losses range from 3.5 to 13.5 percent, with higher losses on hot days. CEC estimated the distribution losses in a 1996 study for Los Angeles Dept of Water and Power and Southern California Edison to be around 9 percent and 7 percent, respectively. Transmission losses have a small effect on the results of the study because generation within the SoCAB covers short distances.

A.4 Emissions from Fuel Production and Distribution Processes

This section describes emissions from feedstock extraction, fuel production, and distribution. The emissions sources are covered roughly in order from extraction through distribution with some overlap. Section A.4.1 reviews emission rates from equipment used in transporting feedstocks and fuel and in processing operations. Energy usage rates for transportation equipment are also discussed in Section A.4.1.

Fuel production emissions and energy inputs are covered in Sections A.4.2 through A.4.3. The allocation of energy use to product fuels is discussed. While fuel production processes have a minor or no effect on marginal NMOG or NO_x emissions in the SoCAB, they are still analyzed as they affect global CO_2 emissions. Fuel processing is defined as the conversion of feedstock material into end use fuel, or fuel production. Feedstock input requirements also relate to feedstock extraction requirements in Section A.4.1. Several fuels are processed from a combination of feedstocks and process fuels. Oil refineries and gas treatment plants produce multiple fuel products. Many production facilities import or export electricity, and excess heat energy can be exported to other facilities,

Section A.4.9 discusses emissions from fuel storage and distribution. These represent the most significant sources of marginal NMOG emissions.

Local fuel cycle emissions are presented in terms of emissions per unit of fuel distributed (i.e. actual gallons of fuel). This approach allows for a more direct comparison with the steps in the fuel cycle.

For example, consider a diesel delivery truck with 7,800 gal of fuel traveling a 50-mi round trip route. A diesel truck fuel consumption of 5 mi/gal is expressed in energy terms as 0.0014 Btu/Btu based on lower heating values. Expressing all of the fuel processing steps in energy terms allows for a convenient comparison amongst different fuel-cycle emission studies. In the case of fuel delivery trucks, a constant mileage is assumed for all fuel types and emissions are calculated from the g/mi emissions and truck fuel capacity to yield g/gal of delivered fuel.

The energy associated with each step in the fuel cycle is also determined to calculate GHG emissions.

Local Emission Constraints

Emissions depend on the location of equipment and the prevailing (and prior) emission standards. Vehicles and combustion equipment in the SoCAB are and will continue to be subject to the strictest emission controls.

SCAQMD limits are as stringent or more so than stationary source requirements in other areas. Table A-13 shows NO_x limits on combustion sources in the SoCAB. Boilers and gas turbines have been subject to Best Available Control Technology (BACT) requirements since the 1980s. All equipment installed since that time would meet NO_x levels consistent with Rule 474. More recent installations will need to meet stricter NO_x limits under Rule 1134. NO_x levels of 9 ppm can only be met with Selective Catalytic Reduction (SCR), and actual emissions with SCR are one-half of this level.

Emission limits under Rules 474, 1110, 1134, and 1146 are expressed in ppm. These were converted to lb NO_2/MMBtu using a fuel factor of 8740 dry scf/MMBtu for natural gas and 9220 dry scf/MMBtu for diesel fuel. These emissions are expressed in lb/MWh or g/hp-hr for the energy consumption assumptions shown in the table.

A.4.1 Fuel Extraction, Transportation, and Processing Equipment

Several types of equipment are used repeatedly throughout the estimation of fuel-cycle emissions. For example, diesel powered tanker trucks are used to move gasoline, diesel, LPG, ethanol, LNG, and methanol fuels from storage locations. Natural gas engines and gas turbines compress natural gas and are used in a variety of fuel industry applications. These engines are used to transmit natural gas feedstock to oil refineries, FT diesel, methanol, and electric power plants. This section summarizes the emissions and estimated usage rates for various types of equipment.

A.4.1.1 Truck Emissions

Tanker trucks are used to haul fuel for local delivery. Table A-14 shows the emissions from heavy-duty trucks. The EMFAC model estimates truck emissions for the average truckload and weight. These estimates are based on engine dynamometer results in g/bhp-hr which are converted to g/mi. The conversion factor implicitly takes into account driving patterns and vehicle loads that probably do not reflect those of tanker trucks.

More stringent emission controls consistent with EMFAC levels were assumed for 2020. These emission rates assume that ARB's 2003 standards which require a 90 percent reduction in NOx and PM are completely rolled into the fleet by 2010.

Table A-15 shows the load carrying capacity of tanker trucks. The gallon carrying capacity depends on the liquid fuel density since the truck must meet axle weight requirements. The values shown in the table are typical for current fuel deliveries. For reformulated diesel, it is unlikely that the load will be varied to take into account small

Table A-13: Summary of SCAQMD NO_x Rules

Rule 474 — Fuel Burning Equipment — Oxides of Nitrogen

Emission Source	Non-Mobil Fuel Burning Equipment						Steam Generating Equipment	
Heat rate (MBtu/hr)	555 to 1,785		1,786 to 2,142		>2,143		>555	
Fuel	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil
NO_x emissions[a]								
(ppmvd @ 3% O_2)	300	400	225	325	125	225	125	225
(lb/MMBtu)	0.37	0.52	0.28	0.42	0.15	0.29	0.15	0.29

Rule 1109 — Emissions of Oxides of Nitrogen for Boilers and Process Heaters in Petroleum Refineries

Emission Source	Boilers and Process Heaters in Petroleum Refineries
NO_x (lb/MMBtu)	0.03

Rule 1110.2 — Emissions from Stationary Internal Combustion Engines (gaseous- & liquid-fueled)

Emission Source	Stationary Internal Combustion Engines	
Energy consumption (Btu/bhp-hr)	8000	8000
Fuel	gas	oil
NO_x emissions[a]		
(ppmvd @ 15% O_2)	36	36
(lb/MMBtu)	0.134	0.141
(g/bhp-hr)	0.48	0.51

Rule 1134 — Emissions of Oxides of Nitrogen from Stationary Gas Turbines

Emission Source	Simple Cycle	Simple Cycle	Simple Cycle No SCR[a]	Simple Cycle	Combined Cycle Power Plant with BACT[c]
Unit size (MW)	0.3 to 2.9	2.9 to 10	2.9 to 10	>10	>60
Energy consumption					
(Btu/bhp-hr)	13,000	13,000	11,000	11,000	5,200
(Btu/kWh)	17,000	17,400	14,750	14,750	7,000
NO_x emissions[a]					
(ppmvd @ 15% O_2)	25	9	14	9	3
(lb/MMBtu)	0.093	0.0337	0.052	0.0337	0.011
(g/hp-hr)	0.55	0.20	0.26	0.17	0.026
(lb/MWh)	1.62	0.58	0.77	0.49	0.078

Rule 1146 — Emissions of Oxides of Nitrogen for Industrial, Institutional, and Commercial Boilers and Process Heaters

Emission Source	Industrial, Institutional, and Commercial Boilers and Process Heaters
NO_x (lb/MMBtu)	0.037

[a]Energy consumption (HHV) values are shown for reference. Emission rules apply on a ppm dry volume basis. NO_x emissions are calculated from fuel factor and O_x content. For example: 300 ppm x 10^{-6} scf NO_x /scf exhaust x 1.17 scf @ 3% O_2/1 scf @ 0% O_2 x n
[b]SCR = selective catalytic reduction
[c]BACT-best available control technology. Emission levels depend upon site specific parameters. Some power plants have been built with 3 ppm NO_x.

Table A-14: Heavy-Duty Truck Emissions

Truck Type	1990 [a,b] 75,000 GVW	1998 [c] 75,000 GVW	1999-02 [c] 75,000 GVW	2003 [c] 75,000 GVW	2020 [d] 75,000 GVW
Fuel Economy (mi/gal)	5.0	5.0	5.0	5.0	5.0
(Btu/mi)	27,560	27,560	27,560	27,560	27,560
Emissions (g/mil)					
CO	11	0.63	0.63	1.01	1.0
NO_X	23.5	23.01	13.36	6.68	0.7
PM	1.2	0.26	0.21	0.26	0.026
NMOG	1.7	0.18	0.18	0.14	0.14
CO_2	2,000	2,000	2,000	2,000	2,000

Source: [a] LACMTA data, adjusted for load (Wool) [b] Davis 1998, adjusted [c] EMFAC 2000, [d] Arthur D. Little

Table A-15: Tank Truck Load for Local Distribution

Fuel	Load (gal)	Fuel Density (lb/gal)	Fuel Weight (lb)	Truckload Energy (10^6 Btu LHV)
RFG3	8,000	6.0	42,500	800
Diesel	7,080	7.2	51,000	926
LPG	10,000	4.2	42,000	832
FTD	8,000	6.4	51,400	950
M100	7,800	6.6	51,500	445
LNG	10,000	3.5	35,000	516
Biodiesel	7,080	7.2	51,000	906
E85	7,800	6.5	46,000	578

Source: To be updated.

differences in fuel density. Some tank trucks are equipped to deliver greater loads. However, the greater fuel load would result in reduced truck fuel economy and greater emissions per mile. The values in Table A-15 are consistent among the alternative fuel options.

Table A-16 shows the distances for hauling fuels by tanker truck with the assumption of a central Los Angeles fueling location. The distances are based on a typical round trip to the appropriate fuel storage site. Petroleum fuels are stored in proximity to oil refineries in the SoCAB with many storage terminals along the coast (Wilmington, El Segundo, etc.). Methanol is currently stored at a chemical terminal in San Pedro. Some finished fuels are trucked further distances.

A.4.1.2 Locomotive/Rail Emissions

Several fuels could be imported into the SoCAB by railcar. LPG produced from natural gas is shipped to California by railcar. If methanol were produced from biomass in the Central Valley, railcar transport would be an option. Emissions are determined from emission rates in g/bhp-hr and cargo load factors in hp-hr/ton-mi shown in Table A-17.

Table A-16: Railcar Distance for Fuel Distribution

Fuel	One-Way Distance (mi)	Location
E100 corn	70	SoCAB
E100 corn	140	CA
LPG – natural gas	70	SoCAB
LPG – natural gas	140	CA
LNG	70	SoCAG
LNG	140	CA

Table A-17: Emission Factors for Rail Transport

Pollutant	Advanced Rail (g/1000 ton-mi)	(g/hp-hr)
NO_x	610.4	7.0[b]
CO	113.4	1.3
CO_2	59,906	687
NMOG	69.8	0.8
PM	8.7	001

[a]Cargo factor = 87.2 hp-hr/net ton-mi.

[b]NOx for older locomotives is 11 g/bhp-hr.

A.4.1.3 Marine Vessel Emissions

Crude oil and finished fuels are shipped in tanker ships. Tankers are powered by steam turbines as well as low speed diesels. The most prominent propulsion system for ocean going tankers is a two-stroke diesel (Burghardt).

Table A-18 shows emissions from typical marine diesel propulsion engines. The NO_x emissions are comparable to or slightly higher than those from uncontrolled truck engines. Fuel consumption in g/bhp-hr is quite low. One reason for the lower fuel consumption is the higher caloric value of the heavy fuel oil used in marine diesels combined with combustion advantages of low speed operation and higher compression ratios. Fuel consumption of marine diesels has dropped from 140 to 120 g/bhp-hr over the past two decades (compared to 215 g/bhp-hr for a diesel engine on the EPA transient cycle). NO_x levels depend on engine load over the ship's operating profile. Emission factors that take into account a ship's operating profile are expressed in g/kg fuel in Tables A-19 and A-20.

Table A-18: Emissions from Marine Diesel Engines

Emission Source	Two-Stroke Diesel, Bunker Fuel	Four-Stroke Diesel, Bunker Fuel
Energy consumption (Btu/bhp-hr)	5890	6086
Fuel consumption (g/bhp-hr)	120 to 140	120 to 140
Emissions (g/bhp-hr)		
NO_x	13.4	10.4
CO	0.15	0.75
CO_2	448	463
CH_4	—	—
NMOG	0.6	0.2
PM	0.5	0.5

Source: Arthur D. Little.

Table A-19: Emissions and Use Factors for Tanker Ship Operations

Emission Source	150,000 DWT tanker 1990 Diesel Motor	Maneuving	Tankers
At sea use factors			
Fuel consumption (kg/ton-mi)	0.0018		
Load efficiency	0.95		
Fuel	Bunker fuel		
Energy content (Btu/kg)	40,350		
At sea emissions (g/kg fuel)	**g/kg**	**lb/1,000 gal**	**lb/1,000 gal**
NO_x	70	639	639
CO	1	58	55
CO_2	3,300	—	—
CH_4	—	19	18
NMOG	4	57	57
PM	1.5	3	3

Sources: Bremnes, Pera.

Table A-20: Emissions and Use Factors for Tug Boats and Ships

Emission Source	Tug Boats and Ships
In port use factors	
Port transit time (h)	2
Hotelling, pumping (h)	30
Tugboat operation (h)	8
Fuel use (kg/visit)	7,716
(kg/DWT)	0.051
Fuel	Diesel
Energy content (Btu/kg)	42,560
In port and tugboat emission factors (g/kg fuel)	
NO_x	37
CO	13.9
CO_2	3,200
CH_4	—
NMOG	6.9
PM	1.5

Sources: EPA AP-42, Kimble.

Tanker capacity is measured in dead weight tons (DWT) which includes the total carrying capacity of the ship. The load efficiency indicates what fraction of the total cargo capacity is actually carried. Fuel consumption decreases with larger tanker size. Tanker carrying load is measured in ton-miles. For marine applications, distance is measured in nautical miles (2000 yards), and speed is measured in knots or nautical miles per hour. For this analysis, crude oil, FTD, and methanol are shipped in 150,000 DWT tankers. Fuel consumption for tankers also varies with tanker speed and ocean conditions. Data from several sources (Kimble) indicate that the fuel consumption for a modern tanker is about 1.8 kg/1000 ton-mi. This fuel consumption is based on a round trip, carrying ballast on the return trip.

Tanker ships also produce emissions while in port. Auxiliary engines operate to produce electric power and tugboats maneuver the tanker into port or to the oil unloading platform. In-port time for tanker ships is generally as short as possible in order to maximize use of the tanker. In-port operation time and fuel consumption were estimated from information included in an ARB workshop on marine emissions. Tugboat fuel consumption is estimated from hours of tugboat operation and tugboat fuel consumption curves. NO_x emission factors are lower for port operations than those for at sea operations because the engines operate at lower load, use lighter diesel oil, and a different mix of engines.

Table A-21 shows the distances traveled by tanker ships. The capacity of the tanker in gallons of product per DWT is also shown. Tankers carry about 95 percent of their weight capacity as cargo with the balance being consumables and ballast. Thus 95 percent of a short ton results in 288 gal of methanol per DWT (2000 lb/ton/6.6 lb/gal × 0.95 capacity.

Table A-21: Overview of Waterway Transportation

Route to Los Angeles	One Way Distance (naut. mi)[a]	Cargo	Capacity (Gallons/DWT)
Singapore	7,500	Crude Oil	247
Singapore	7,500	Methanol	288
Singapore	7,500	FTD	260
Singapore	7,500	LNG	400
Illinois	4,300	Ethanol	288

[a]Nautical Mile = 1.136 mile = 2,000 yards.

Table A-22 shows the marine transportation distance assumptions. The percentages represent the weighted average of the shipping distance that corresponds to the locations indicated in the table. Tanker travel distance in the SoCAB is taken to be 26 nautical miles. Several studies have considered the appropriate distance to include for marine vessel inventories (Port of Los Angeles). The SCAQMD boundaries include a 32 nautical mile section towards Ventura County and an 18 nautical mi. section to the South. Other studies have drawn an 88 nautical mile radius from shore or a similar shape out past San Clemente Island. Tanker ships probably reduce their power and coast when entering port that would lead to lower emissions along the coast. A relatively shorter (26 mi) tanker travel distance was assumed for this study while tanker emissions are not adjusted for reduced load. Assuming a longer distance and lower emissions would yield a similar result.

Table A-22: Partition of Marine Transport Distances[a]

Location	Singapore, Indonesia	Decator, Illinois; Santiago, Chile
Mileage Allocation		
SoCAB	26	26
CA	0	50
U.S.	0	0
ROW	7620	4700

[a] One-way distance, nautical miles.

A.4.1.4 Engine Emissions

Table A-23 summarizes the emission and performance characteristics of natural gas turbines used for natural gas transmission, prime movers. Table A-23 shows estimates of current and future emissions for turbines operating in the SoCAB, California, and the United States. Turbines operating outside of North America are assumed to emit at 1990 United States levels.

Table A-23: Natural Gas Turbine Emissions

Turbine Location	SoCAB		CA, U.S.	
Year	**1996**	**2010**	**1996**	**2010**
Energy consumption (Btu/bhp-hr)	**11,000**	**10,500**	**11,000**	**10,500**
Emissions (g/bhp-hr)				
NO_x[a]	0.3	0.17	1.4	0.5
CO	0.83	1.0	0.83	1.0
CO_2	600	574	600	574
CH_4	0.2	0.2	0.2	0.2
NMOG	0.01	0.01	0.01	0.01

[a] SCAQMD Rule 1134 requirements are equivalent to 0.03 to 0.5 g/bhp-hr.

Sources: Huey, A. D. Little, EPA. 1999.

Emissions in Table A-23 are shown in g/bhp-hr. These are converted to g/100 scf of natural gas transmitted.

Energy consumption (Btu/bhp-hr) and emissions are based on a population profile of gas turbines used as natural gas prime movers (Huey 1993) and emissions data for individual makes and models of gas turbines. The range of energy rates for gas turbine prime movers can vary from 10,000 to 13,000 Btu/bhp-hr. Heating values for stationary equipment is shown on a higher heating value (HHV) basis that is standard practice in the U.S. Further calculations involve lower heating values (LHV).

NO_x emissions for gas turbines located in the SoCAB are based on SCAQMD Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines) and an estimate of the types of gas turbines in the region. Because the NO_x limit set forth in Rule 1134 varies according to control technology and rated power output, the NO_x emission factor is an average emission factor for several types of gas turbines with varying power output and control technologies. The future NO_x emission factor for gas turbines in the SoCAB is based on the emissions from the best available control technologies for gas turbines.

HC and CO emissions are consistent with EPA emission factors. CO_2 emissions are proportional to energy consumption.

Emissions data also show that methane emissions make up over 90 percent of the Total Hydrocarbons (THC) emissions from a gas turbine.

Table A-24 summarizes the emission and performance characteristics of natural gas reciprocating engines used for natural gas transmission, prime movers. Engines outside of North America are assumed to emit at the 1990 U.S. level.

Table A-24: Natural Gas Reciprocating Engine Emissions

Engine Location	SoCAB		ROW	CA, U.S.	
Year	1996	2010	1990	1996	2010
Energy Consumption (Btu/bhp-hr)	8,000	7,800		8,000	7,800
Emissions (g/bhp-hr)					
NO_x[a]	2	0.48	6	5	2
CO	2.7	2.7	2.7	2.7	2.7
CO_2	438	427	438	438	427
CH_4	4.42	5	5	5	5
NMOG	0.45	0.5	0.5	0.5	0.5

[a] SCAQMD rule 1110.2 requirements are equivalent to 0.34 to 0.61 g/bhp-hr.

Sources: Huey, EPA 1999, A. D. Little

Energy consumption is based on a population profile of reciprocating engines prime movers (Huey) and emissions data for individual makes and models of engines. This value can range from 6,000 to 10,000 Btu/bhp-hr.

Population profiles of reciprocating engine prime movers indicate that the majority of these engines are lean-burn, with relatively few being stoichiometric rich-burn engines. The emission factors assigned to reciprocating engine prime movers are associated with lean-burn engines. Uncontrolled lean burn engines do not operate sufficiently lean to provide significant NO_x reductions. All new lean burn engines sold in North America are configured for low NO_x emissions.

NO_x emissions outside the SoCAB (CA and the U.S.) are estimated to be 5 g/bhp-hr, which is based on an engine prime mover population and emissions profile. NO_x emissions for an uncontrolled lean-burn prime mover range from 10 to 12 g/bhp-hr, whereas the emissions for a controlled lean-burn prime mover are about 1 to 2 g/bhp-hr (Huey 1993). Future NO_x emissions for engines located in the SoCAB are estimated to be 0.48 g/bhp-hr, based on SCAQMD Rule 1110.2 (Emissions from Stationary Internal Combustion Engines).

CO and HC emissions are based on EPA emission factors and CO_2 is calculated from energy consumption and fuel properties. Similar to gas turbines, the emissions data also show that methane emissions makes up over 90 percent of the VOC emissions from an engine.

A.4.1.5 Biomass Collection Equipment

Fuels and feedstocks are transported and distributed by a variety of equipment including trucks, trains, and marine vessels. Emissions from fuel or material transport were determined from emission rates and equipment usage factors that take into account distance traveled and cargo load. The emissions and use factors for the relevant fuels are discussed for each transportation mode. Several types of biomass are potential feedstocks for fuel production. Such feedstocks include agricultural wastes, wood waste, and purpose grown energy crops. Potential energy crops include poplar and eucalyptus. Feedstock transportation requirements for combustion of agricultural material and forest residue were used to estimate fuel usage in this study.

Emission factors from an ARB study on farming equipment are shown in Table A-25. The study considered a range of equipment power that did not vary substantially (for the overall emission factor) in NO_x. The most prominent size range for agricultural equipment is used in this study. Typical energy consumption values are assumed for diesel equipment and increased by 20 percent for gasoline.

Table A-25: Off-Road Equipment Emissions

Equipment Type	1996 Diesel 101-175 hp	2010 CA Diesel	1996 Gasoline 4-stroke 40-100 hp	2010 Gasoline
Energy consumption (Btu/bhp-hr)	9,350	9,200	11,200[a]	11,000
Fuel consumption (g/bhp-hr)	220	216	244	240
Emissions (g/bhp-hr)				
NO_x	11	7	3.0	3.0
CO	3.4	3.4	235	235
CO_2	640	630	720	704
CH_4	0	0	0	0
NMOG	1.1	1.1	8.25	6.6[b]

[a] 20 percent increase in energy consumption with gasoline.
[b] 20 percent reduction in mass emissions with RFG.

Sources: Kreebe 1992, EPA 1999, A. D. Little.

Evaporative emissions were estimated from ARB's study on off-road emissions. For the 40 to 100 hp category of agricultural equipment, evaporative emissions were 550 lb/unit per year, of which 98 percent were running losses. Running losses in the ARB study were based on the EMFAC emission factor for uncontrolled automobiles. The study indicates 5248 operating hours per year and 32,906 gallons per year of fuel use for 70-hp equipment. The evaporative emissions are then 7.6 g/gal. An additional 4 g/gal average was added for uncontrolled fueling emissions (see Table A-39). Evaporative emissions for RFG- and diesel-fueled equipment were adjusted for the vapor pressure in proportion to the mass emissions.

The CEC and DOE have explored numerous approaches for producing biomass feedstocks. Two studies included estimates of energy inputs for wood-based feedstock in California (Tiangco, Graham).

Usage rates for farming equipment in Table A-26 are combined with fuel production yields in Table A-27. The study shows diesel energy as a proxy for petroleum fuels and other energy inputs. Table A-26 shows the energy components for diesel in greater detail. ARB's off-road emission study (Kreebe) indicates that 10 percent of agricultural equipment is gasoline-fueled. Energy requirements for biomass hauling are estimated for a truck, with a fuel economy of 5 mpg, hauling 27 dry tons of biomass over a 50-mile round trip. The energy requirements per unit of product fuel are based on the process yield considerations.

Table A-26: Energy Input for Biomass Collection

	Forest Material		Urban Wood Waste	
Energy Input	**gal/ton**	**Btu/lb Biomass**	**gal/ton**	**Btu/lb Biomass**
Diesel equipment	2.2	120[a]	1.2	70
Gasoline equipment	—	15[a]	—	8
Electricity	5 kWh	0.0025 kWh	5 kWh	0.0025 kWh
Diesel transport	0.7	37	0.86	64

[a] The split between gasoline and diesel is estimated on a Btu/lb basis from Kreebe.

Sources: Kreebe 1992, Perez 1999, A. D. Little

Table A-27: Energy Input for Biomass Collection per Gallon of Ethanol

		Energy Consumption (Btu/gal)			(kWh/gal)
Product	**Yield^{-1} (lb/gal)**	**Diesel Equipment**	**Gasoline Equipment**	**Diesel Truck**	**Electric Power**
Ethanol	75 lb/gal	9610	880	3300	0.19

While the collection of biomass results in emissions from gasoline and diesel equipment, the overall emissions associated with feedstock collection are likely to be a net negative. Collecting agricultural residue or forest waste results in a reduction in emissions from prescribed burns or wildfires. Therefore, fuel cycle emissions impacts are not included outside of urban areas. A report from the Energy Commission assesses the value of these emission reductions (Perez 2001).

A.4.2 Refinery Emissions

A variety of petroleum products are produced from crude oil. Refineries produce gasoline, diesel, kerosene/jet fuel, LPG, residual oil, asphalt and other products. A variety of co-feedstocks, including natural gas, electricity, hydrocarbons from other refineries, and MTBE and other oxygenates, complicates the analysis of fuel-cycle emissions. Different crude oil feedstocks, gasoline specifications, and product mixes also complicates the picture for refineries.

Determining the emissions from the production of petroleum products involved the following approach. The SCAQMD emissions inventory includes emissions from oil production, refining, and distribution. These emissions are broken down by type, e.g. fugitives from valves and flanges. Emissions from base year, 1996, is based on emission use fees from stationary sources. These values were the basis for determining emissions on a gram per total amount of petroleum production basis. However, these emissions need to be allocated to the various refinery products in order to reflect the energy requirements for producing different fuels.

The output from a refinery model was used to determine the energy inputs required to produce different gasoline, diesel, and other petroleum products (MathPro 1999). Refinery combustion emissions were allocated to gasoline, diesel, and LPG in proportion to the energy requirements for refinery units. An energy allocation model was also used to determine changes in refinery energy needed to produce diesel and LPG. This approach results in the average emissions from refineries.

Emissions from refinery units in the model were allocated to the petroleum products produced by each refinery unit. For example, all of the combustion emissions associated with the diesel hydrodesulfurization unit are attributed to diesel fuel. Table A-28 shows the allocation of crude oil energy input and imported energy to diesel, RFD, and LPG.

Table A-28: Allocation of Product Output and Energy Consumption for Refineries

Product	Crude Oil (gal/gal)	Natural Gas (100 scf/gal)	Electric Power (kWh/gal)	Energy[a] (Btu/gal)
RFG[b]	0.94	0.18	0.27	157,000
Diesel	1.04	0.09	0.13	163,000
RFD	1.04	0.12	0.25	178,500
LPG	0.71	0.05	0.05	111,400

[a] Energy inputs based on allocation of energy inputs for MathPro refinery model. 103,000 Btu/100 scf natural gas and 9,000 Btu/kWh power.
[b] Includes 5.7% ethanol.

Source: A. D. Little

A.4.2.1 SCAQMD Inventory

The SCAQMD emissions inventory provides insight into emissions from oil production, refining, and distribution in the four county SoCAB. Refineries and oil producers submit emission fee forms annually to the SCAQMD. Emissions for these forms are determined from either published emission factors or from source testing. These values make up SCAQMD's base year inventory.

Most of the emission rates are determined from calculations that depend on equipment type and throughput using SCAQMD and AP-42 emission factors. Other emissions are determined from source testing.

The SCAQMD inventory is determined for average days as well as summer and winter days. The summer inventory was examined in this study since it is intended to represent conditions for maximum ozone formation. The summer inventory may not be representative of the petroleum industry since refineries operate at fairly constant capacity and are not affected by seasonal activities. The summer inventory may also be adjusted for increases in temperature and higher evaporative emissions. Higher RVPs in the winter might cancel out the temperature effect; however, crude oil breathing losses will be higher.

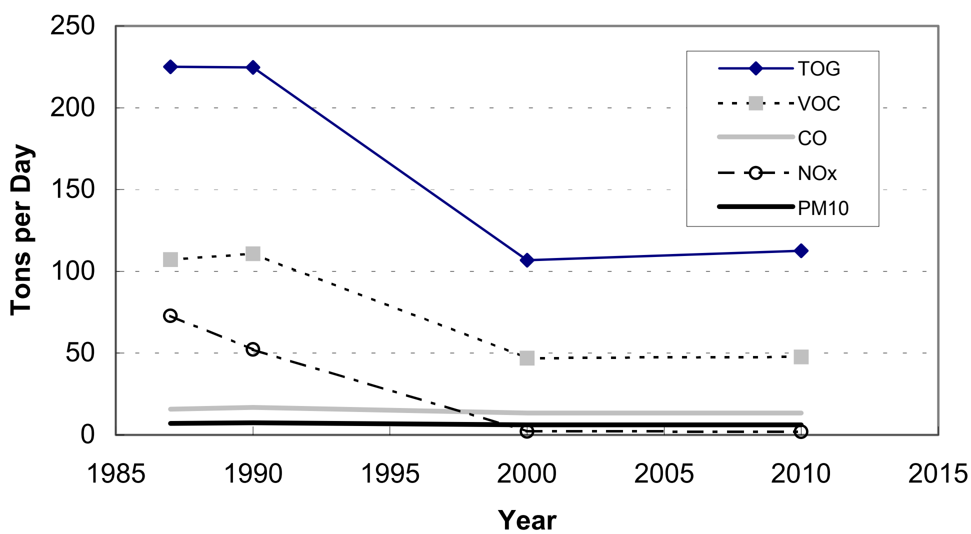
Table A-29 shows the SCAQMD TOG and VOC summer inventory for the years 1987, 1990, 2000, and 2010 for the SoCAB (SCAQMD 1996). The inventory of TOG, VOC, NO_x, CO, and PM_{10}, is also shown in Figure A-1. Since the sources emit hydrocarbon emissions, TOG corresponds to total hydrocarbons and VOC corresponds to NMOG. The inventory shows no reductions in VOC emissions between 2000 and 2010. This result depends on assumptions in the inventory calculations that are not readily

Table A-29: SCAQMD Inventory for Oil Production, Refining, and Marketing

Source Category	VOC (tons/day) 1987	1990	2000	2010
Fuel Combustion				
Oil and gas production	0.80	0.66	0.56	0.56
Petroleum refining	1.68	1.39	1.33	1.33
Petroleum Process, Storage & Transfer				
Oil and gas extraction	38.70	43.30	11.68	11.70
Petroleum refining	23.61	21.79	9.08	9.16
Petroleum marketing	40.76	40.99	22.29	22.81
Other	1.60	2.62	2.00	2.24
Total	**107.2**	**110.8**	**46.9**	**47.8**

Source: SCAQMD 1997.

Figure A-1: SCAQMD Inventory for Oil and Gas Production, Refining, and Marketing



Source: SCAQMD 1996.

correlated to emission rules. The inventory shows an increase in petroleum marketing emissions from 2000 to 2010, which reflects growth in gasoline demand. New ARB rules require further reductions in refueling emissions. The inventory values are shown as a point of reference while fuel-cycle emissions are based on per gallon calculations.

Table A-30 shows the VOC emissions from oil production on g/gal basis. The refining and production values in Table A-25 are shown on a total refinery emissions per gallon of gasoline basis. These values provide a point of comparison for determining average emissions that are not a focus of this study.

Table A-30: NMOG Emissions from SCAQMD Oil Production and Refining (g/gal)[a]

Emission Source	1990	2010
Oil production	0.449	0.277
Oil refining	0.929	0.812

[a] Total (average emissions) per gallon of gasoline.

A.4.3 Alternative Fuel Production

The criteria pollutant emissions associated with methanol, FTD, ethanol, CNG, and LNG all occur outside of the SoCAB. As discussed in A.3, they are all produced in other regions of California or are imported from other states or countries. The emissions from these fuels are discussed in detail in the 2001 ARB Fuel Cycle Report (ARB 2001b) and in the 2001 CEC Biomass-to-Ethanol report (Perez, 2001).

A.4.4 Fuel Storage and Distribution

This section describes the bulk storage and delivery of liquid fuels. Table A-31 shows the emissions from bulk storage tanks based on the calculation technique in AP-42.

According to the staff of the SCAQMD refinery and bulk storage inspection and permitting teams, floating roof tanks are the most common storage tank type in the SoCAB. These tanks comply with “Rule 463: Organic Liquid Storage” which regulates the storage of gasoline in above-ground tanks among other compounds. Tanks in bulk storage farms and refineries are often used to store more than one type of product including diesel and other intermediary refinery product.

Vapor controls are required to be at least 95% efficient. Internal and external floating roof tanks must be equipped with liquid mounted primary and secondary seals consistent with the best available technology. Other tanks are outfitted with vapor recovery systems that feed the recovered vapor either into an incinerator or a liquifier. In the study, a 90 percent reduction in emissions (reduction factor of 0.1) is assumed for

Table A-31: Fugitive Hydrocarbon Emissions from Internal Floating Roof Storage Tanks

Fuel	Gasoline	Diesel	FT Diesel	E100	M100
RVP (psi)	6.80	0.022	0.030	2.3	4.63
TVP (psi)	6.10	0.015	0.02	1.7	3.50
Temperature (°F)	90	90	90	90	90
MW	76	130	120	46	32
Tank capacity (bbl)	50,000	50,000	50,000	50,000	50,000
Tank diameter (ft)	100	100	100	100	100
Tank height (ft)	36	36	36	36	36
Throughput (bbl/yr)	600,000	600,000	600,000	600,000	600,000
Throughput (gal/day)	69,041	69,041	69,041	69,041	69,041
Turnover (day/tank)	30.42	30.42	30.42	30.42	30.42
Emissions (lb/yr)	6855	88	94	965	1,663
Emissions (g/gal)	0.1235	0.0016	0.0017	0.0174	0.0300

Source: A. D. Little

methanol tanks in the SoCAB. Such controls were not assumed for diesel because its low vapor pressure avoids vapor control requirements.

Actual NMOG emissions are either capped by Best Available Control Technology requirements in the SoCAB or are naturally lower due to low vapor pressure, as indicated in Table A-32.

Table A-32: NMOG Emissions from Bulk Fuel Storage

Fuel	Vapor without control (g/gal)	BACT (g/gal)
Gasoline	0.123	0.0246
Diesel	0.0016	0.0246
FT Diesel	0.0017	0.0246
E100	0.0174	0.0246
M100	0.030	0.0246

Source: A. D. Little

A.4.4.1 Local Fuel Distribution — Liquid Fuels

This section describes the storage and distribution of liquid fuels at local service stations. These emissions consist of the following categories:

- Tank truck unloading spills and working losses: tank trucks unload fuel to storage tanks at fueling stations using Phase I vapor recovery.

- Under ground tank breathing: during the course of fuel storage, the vapor or ullage space in the tank expands and contracts as atmospheric pressure and fuel temperature change. Fuel temperature usually remains almost constant in underground tanks.

- Vehicle fuel tank filling (working losses): fuel is dispensed to vehicles with vapor recovery hose systems, called Phase II vapor recovery.

The different stages of fuel distribution were observed to provide insight for this project. There are no significant differences in the unloading of gasoline or alcohol fuels. Fuel unloading at service stations is performed by the tank truck operator who may be an oil company employee or work for an independent company. Unloading is accomplished with appropriate precautions for safety and minimizing emissions. Fuel and vapor transfer hoses are connected from the storage tank to the truck. The truck carries its own fuel transfer hoses and an assortment of fittings for connection to the underground tank. After verifying the remaining tank volume with a dipstick measurement, the truck operator initiates the gravity fed unloading operation. When the fuel transfer is completed, the hoses are returned back to the tank truck. There is still a considerable volume of fuel in the fuel transfer hose (about 4-inch inner diameter). The truck operator disconnects the hose from the truck tank and drains the remaining fuel in the bottom of the hose into the underground storage tank by lifting the hose into the air and moving the elevated section towards the connection at the underground tank. The hose is then disconnected and stored on the truck. During several such fueling operations, about 250ml of fuel was observed spilling out of the hose as it was placed back into its holding tube on the truck. It was estimated that the volume from spills is about 180g for an 8000 gal fuel load or 0.023 g/gal (0.05 lb/1000 gal). While this quantity is based on casual observations, it provides some quantification of a small source that is not explicitly counted in the inventory. It is difficult to spill no fuel during hose transfers since the inner wall of the transfer hose is covered with fuel as indicated by hooks on some tanker trucks for drying clean up rags. An even smaller amount of fuel may remain on the hose surface and evaporate later.

Truck transfer is intended to be a no spill operation. Drivers are instructed to drain the hose into the tank before placing it back on the truck. Catch drains at the top of underground tanks would capture some spilled fuel if it dripped from the tank connection. However, some wet hose losses are inevitable. The thin layer of fuel in the hose will result in some drips and evaporation. It should be pointed out that the volumes used in this study are based on rough estimates and do not reflect a large sample. Furthermore, liquid spill volumes are difficult to measure. While further quantification of the frequency and quantities of Phase I spillage would be necessary to assure the accuracy of this value, it is significantly smaller than Phase II spillage.

A.4.4.2 Vehicle Fueling Spillage

While most vehicle operations are successful with little fuel spilled from the nozzle, occasionally a significant quantity of fuel is spilled. Fuels spills and form vehicle refueling were evaluated by ARB in the Enhanced Vapor Recovery Standards and Specifications (July, 2001). The proposed rulemaking set standards for spillage, drips, and nozzle retention. These standards are presented in Table A-33. For calculation purposes, spillage, liquid retention, and nozzle spitting are lumped together on a g/gal basis. All of these emissions are event related. The amount of fuel spilled per event is constant; so, larger fuel tanks or volumes of fuel dispensed result in lower emissions per gallon dispensed. Historically, emission factors for spillage have been 0.7 lb/1000 gal. With Phase II systems, this value was adjusted downward to 0.24 lb/1000 gal. For Phase II systems, spillage plus liquid retention results in 0.40 lb/1000 gal of gasoline.

Table A-33: Standards for Gasoline Spillage, Dripping and Nozzle Retention

Source	Standard	Units
Phase II dispensing spillage	0.24	lb/1000 gal
Dripless nozzle	<1	drops/fueling event
Liquid retention	100	ml/1000 gal
Nozzle spitting	1	ml/nozzle

Source: ARB 2001

The liquid retention emissions are based on gasoline evaporating from the nozzle. With methanol, this level of evaporation would be lower, and it would be virtually eliminated with diesel. The ARB emission factor for diesel spillage is 0.61 lb/1000 gal. The maximum for diesel spillage is higher than that of gasoline for several reasons. Since vapor emissions from diesel are much lower than those from gasoline, a higher spillage rate is allowed in the rules. Since diesel fueling occurs without vapor recovery, higher fueling rates are possible. The potential for spillage is potentially higher with higher fueling rates.

Service station fueling practices were also observed to evaluate vehicle fueling. The dispensers at numerous fuel stations were polled to determine the amount of fuel dispensed per fueling event. The amount of fuel dispensed ranged from one half to 18 gallons with an average of 8 gallons[1]. The emissions actually depend on the number of fueling events rather than fuel volume but since spillage is measured per volume of fuel, the volume of fuel dispensed is important to know. Various vapor recovery nozzle types are used at service stations in California. At self-service stations, the vehicle driver dispenses the fuel. Most customers select the lower price self-service option.

[1] Four fueling stations survey in 1996, 12 fueling stations in 1998.

In 1994 API published a study that indicated a spillage emission rate of 0.31 lb/1000 gal while the value used in emission inventories was 0.7 lb/1000 gal. An even lower spill emission factor is assumed for new gasoline vehicles with Phase II controls. The lower spill emission rates that are expected to apply by 2010 and are assumed in emission inventories are based on nozzle performance that is consistent with certification requirements.

Spillage rates of other liquid fuels were estimated. The low emission case is shown in Table A-34 and the higher emission case is shown in Table A-35. In the high emission case, it is assumed that increases in fuel economy reduce the size of the tank, thereby causing higher spillage per volume of fuel (even though spillage per refueling or per vehicle per year would be much lower with higher economy vehicles). The diesel emission rates are consistent with the 0.61 lb/1000 gal assumed in the inventory. FTD spillage volume is assumed to be the same as that of diesel. Since FTD has a lower density, the mass per gallon of spillage is slightly lower. Both gasoline and M100 are subject to Phase II emission controls so the spillage emissions are assumed to be the same per fueling event. Spillage emissions per gallon depend upon refueling volume, which is estimated from vehicle fuel economy to be consistent with the 8 gallons per fill for gasoline vehicles. The average fill volume assumed for gasoline is 8 gallons. An increase in fuel tank capacity is expected for alternative-fueled vehicles.

Table A-34: Vehicle Fuel Spillage Parameters for 2020

Fuel	Fill Volume[a] (gal)	Tank Size (gal)	Fuel Economy (mpg)	Volume (NMOG, mL)	Liquid Retention/Spillage (g/gal)
Diesel	8.0	14.5	41.8	2.56	0.277[b]
RFD	8.0	14.5	41.8	2.56	0.277
LPG	11.2	20.4	21.5	2.0	0.090
FTD	8.0	14.5	38.0	2.56	0.249
M100 FC	11.6	21.0	20.9	2.02[c]	0.138
Gasoline	8.0	14.5	30.2	2.02	0.182

[a]Fuel tank size is not reduced for diesel, FTD.
[b]0.61 lb/1000 gal for non-Phase II fueling.
[c]Same spillage volume as gasoline.

Source: Arthur D. Little

Table A-35: Vehicle Fuel Spillage Parameters for worst case in 2020

Fuel	Fill Volume[a] (gal)	Tank Size (gal)	Fuel Economy (mpg)	Spill Volume (NMOG, mL)	Spillage (g/gal)
Diesel	5.8	10.5	41.8	2.56	0.383
RFD	5.8	10.5	41.8	2.56	0.383
LPG	11.2	20.4	21.5	2.0	0.091
FTD	6.4	11.6	38.0	2.56	0.313
M100 FC	11.6	21.0	20.9	2.66	0.182[b]

[a]Fuel tank size reduced with improved fuel economy.
[b]Emission factor for gasoline fueling.

Source: Arthur D. Little

A.4.4.3 Vapor Space NMOG Mass

Vapor emissions in this study are determined from modeled vapor concentrations. The fuel temperature used to determine vapor concentrations was selected to be consistent with ARB's inventory for fueling station emissions.

The vapor concentration in the tank vapor space is the basis for fuel transfer emission calculations in AP-42 and provides insight into the temperature conditions for vapor emissions. Vapor space concentrations are modeled from equilibrium vapor concentration. The extent of vapor saturation is reflected by the saturation factor. For vapor recovery systems a saturation factor of 1.0 or completely saturated vapor is assumed in AP-42. ARB bases the vapor space concentration on test data. The vapor space gas concentration represents the uncontrolled emissions from tank truck unloading (underground tank working losses), and vehicle tank working losses.

Vapor space concentrations from liquid fuels were estimated from the ideal gas law. Given a molar volume of 379.6 ft^3/lb mole at 60°F, the equilibrium vapor (V_e) in a tank head space can be calculated from the following equation:

$$V_e\ (\text{lb/gal}) = \text{MW(lb/mol)} \times \text{lbmol}/379.6\ \text{ft}^3 \times 0.1337\ \text{ft}^3/\text{gal} \times \text{TVP}/14.7\ \text{psi} \times 520°\text{R}/\text{T}$$

Where:

T = gas and liquid temperature (°R)
TVP = true vapor pressure (psi) at the equilibrium temperature

The same temperature conditions were emission estimates that are consistent with California inventories. This effectively results in an equivalent equilibrium temperature that reflects the actual range of fuel temperatures and saturation conditions that correspond to test data. The underlying assumption with this approach is that the inventory data is based on a broad range of conditions and reflects the suitable conditions. Shown in Table 4-36 are the vapor densities, which vary with temperature.

Table A-36. Evaporative Emissions from Local Fuel Distribution

Fuel/ Emission Category	RVP	Ef fective Temperature (°F)	Uncontrolled NMOG Vapor Mass g/gal)	(lb/1000gal)	w. Control (g/gal)
Diesel UG tank working loss	0.022	70	0.009	0.02	0.009
Diesel UG tank working loss	0.022	76	0.011	0.02	0.011
Diesel UG tank breathing loss	0.022	70	0.0009	0.002	0.001
Diesel Vehicle working loss	0.022	76	0.011	0.02	0.011
Diesel Vehicle working loss	0.022	80	0.012	0.03	0.0120
Diesel Vehicle working loss	0.022	90	0.017	0.04	0.017
FTD UG tank working loss	0.03	70	0.012	0.03	0.012
FTD UG tank working loss	0.03	76	0.014	0.03	0.014
FTD UG tank breathing loss	0.03	70	0.0012	0.003	0.001
FTD Vehicle working loss	0.03	76	0.014	0.03	0.014
FTD Vehicle working loss	0.03	80	0.015	0.03	0.0151
FTD Vehicle working loss	0.03	90	0.021	0.05	0.021
M100 UG tank working loss	4.5	70	0.68	1.5	0.014
M100 UG tank working loss	4.5	76	0.79	1.7	0.016
M100 UG tank breathing loss	4.5	70	0.07	0.1	0.007
M100 Vehicle working loss	4.5	76	0.79	1.7	0.040
M100 Vehicle working loss	4.5	80	0.87	1.9	0.044
M100 Vehicle working loss	4.5	90	1.15	2.5	0.058
RFG UG tank working loss	6.8	70	3.04	6.7	0.061
RFG UG tank working loss	6.8	76	3.45	7.6	0.069
RFG UG tank breathing loss	6.8	70	0.30	0.7	0.030
RFG Vehicle working loss	6.8	76	3.45	7.6	0.173
RFG Vehicle working loss	6.8	80	3.68	8.1	0.184
RFG Vehicle working loss	6.8	90	4.42	9.7	0.221
M85 UG tank working loss	7.2	70	1.98	4.4	0.040
M85 UG tank breathing loss	7.2	70	0.20	0.4	0.020
M85 Vehicle working loss	7.2	76	2.26	5.0	0.113
M85 Vehicle working loss	7.2	80	2.44	5.4	0.122
M85 Vehicle working loss	7.2	90	2.98	6.6	0.149
E85 UG tank working loss	6.8	70	2.48	5.5	0.050
E85 UG tank breathing loss	6.8	70	0.25	0.5	0.025
E85 Vehicle working loss	6.8	76	3.31	7.3	0.166
E85 Vehicle working loss	6.8	80	3.54	7.8	0.177
E85 Vehicle working loss	6.8	90	4.18	9.2	0.209
E100 UG tank working loss	2.3	70	0.442	0.97	0.009
E100 UG tank breathing loss	2.3	70	0.044	0.10	0.004
E100 Vehicle working loss	2.3	76	0.524	1.2	0.026
E100 Vehicle working loss	2.3	80	0.578	1.3	0.029

[a] Tank working loss control factor = 98%, breathing control factor =90%, Vehicle working loss control factor =95%, Defect rate = 0% for vehicle losses

[b] No vapor control on diesel, ORVR eliminates defect rate for vapor controls

Vapor concentration (uncontrolled NMOG vapor mass) for this study was determined from equilibrium vapor densities that correspond to 70°F for underground tank vapors, and 76°F for vehicle fuel tank vapors. Actual vehicle vapor temperatures can be higher. The effect of higher vapor temperatures is also shown in Table 4-38.

Table 4-38 also shows tank truck distribution emissions for liquid fuels. These emissions take into account vapor recovery effectiveness and a defect rate between zero and four percent for Phase II emission controls. The higher defect rate reflects the potential interaction between ORVR equipment and vapor control equipment or simply a less effective vapor recovery system. Since no methanol powered fuel cell vehicles or any passenger cars that operate on M100 are built in commercial volumes, emission control requirements can still be developed. Such emission control requirements would address Phase II efficiency requirements, refueling connections that reduce the risk of misfueling, ORVR requirements, and other details of refueling.

A.4.4.2.3 LPG Distribution

LPG is stored and distributed in pressurized tanks. The fuel is stored in a liquid state at ambient temperature and the pressure in the tank is in equilibrium. At 70°F the storage pressure is 105 psig. When LPG is transferred from a storage tank to a tank truck, or to a vehicle fuel tank, a transfer pump provides about 50 psi of differential pressure. When fueling vehicle tanks, the fuel enters the tank and the LPG ullage condenses. This process can be accelerated with top loaded tanks where the liquid spray can absorb some of the heat from condensing the vapors.

The tank trucks are filled at refineries with a two hose system with one hose acting as a vapor return. Hoses are evacuated after fuel transfer operations at the refinery. Tank trucks can be filled to a safe fraction of its water capacity by weighing the truck during fueling (Lowi 1994), although this is not the current practice. However, current regulations require the use of an "outage" valve that indicates when the tank is full. Some LPG also enters the atmosphere from the fuel transfer fitting.

Table 4-37 shows the emissions associated with LPG storage and distribution. The LPG emissions correspond to the volume of liquid that escapes from the fuel transfer fitting divided by the amount of fuel transferred. Currently, LPG vehicles in California are equipped with an “outage” valve that indicates the 80 percent fill level by spilling LPG to the atmosphere. During vehicle fueling, the outage valve is opened and vapors pass through a 0.060-inch orifice and through the valve. When LPG reaches the 80 percent level in the vehicle tank, liquid enters the fill level line and exits into the atmosphere. A puff of white liquid is visible to the fueler that provides an additional signal that the tank is full. California's vehicle code requires use of the outage valve. As indicated in Table A-37, emissions from vehicle fueling are several grams per gallon.

Table A-37: Fuel from LPG Fuel Delivery

Emission Source	Tank Volume (gal)	Liquid Spill Volume (ml/fill)	(ml/gal)	Spill Rate (g/gal)
Transfer tank outage[a]	10,000	—	—	1
Bulk tank outage	30,000	—	—	0.2-0.5
Truck fill outage[a]	—	—	—	2
Truck fill hose	3,000	1,391	0.139	0.070
Local tank hose	1,000	17.4	0.0017	0.0008
Local tank outage[a]	—	—	—	5
Vehicle tank outage	—	—	—	0

[a]Better vapor management could eliminate this emissions source by the year 2010.

Many LPG tanks are already equipped with automatic stop-fill devices that could eliminate fuel tank vapor venting; however, Titles 8 and 13 of the California Administrative Code require the use of the outage valve. Other countries, including the Netherlands where many LPG vehicles operate, do not use the outage valve for fueling. One might expect that many LPG vehicles in California are fueled without using the outage valve if they are equipped with automatic stop fill devices.

A committee of NFPA, CHP, NPGA, and WLPGA representatives are working to set standards that will allow LPG vehicles to be fueled without leaking LPG to the atmosphere. Equipment that will minimize the fuel released from transfer fittings is also being approved (Wheeler 1994). EPA regulations on evaporative emissions from vehicles will also eliminate vehicle outage valve emissions.

Emission estimates for LPG fueling are based on the following conditions:

- 1391 cc loss from fuel couplings on 10,000 gal delivery trucks. Fluid loss is equivalent to 18 in of 1.25-in (inner diameter) hose (Lowi 1992)

- Current vehicle hose coupling liquid losses are 7.57 cc (Lowi 1992) for a 12 gallon fuel transfer. Dry-break couplings would have less than 5 percent of the trapped volume of current LPG nozzles of the same capacity.

- Current fuel tank vapor displacement is based on sonic flow through a 1.5 mm orifice, 70°F tank temperature with a fuel pressure of 105 psig. Assuming an orifice discharge coefficient of 0.5 results in 2 g/s of vapor flow. With an 8 gal/min flow rate, vapor displacement is 15 g/gal.

- Vapor displacement from current tank truck filling assumes a 100 gal/min fill rate with an outage loss of 2 g/s

A.5 Local Vehicle Emissions

Fuel cycle emissions per unit fuel were calculated for the fuels discussed in Section 3. Emissions were calculated for NO_x, PM, CO, and NMOG based on transportation, distribution, and other steps in the fuel cycle that result in marginal emissions. Emission estimates were made for each step in the fuel cycle shown below:

- Feedstock transport
- Refinery
- Fuel Transport
- Fuel unloading
- Bulk terminal
- Truck loading
- Truck Spillage
- Truck Exhaust
- Truck Unloading
- Storage Tank Breathing
- Vehicle Working Loss
- Spillage

The emissions are grouped to provide a comparison among different fuels and to allow for the calculation of toxic emissions. The results for the fuels in this study are shown in Tables A-38 through A-45. These tables show the base case estimate that corresponds to compliance with all emission standards. A worst case is also presented which assumes higher rates of vehicle spillage, less control of evaporative losses, and higher NO_x and PM emissions from diesel trucks.

Marginal fuel cycle emissions include combustion exhaust and hydrocarbon losses. Combustion emissions include primarily fuel transportation (and power plant emissions for EVs). The transportation emissions are determined from distances in urban areas and the rest of California combined with emission factors for transportation equipment and other parameters discussed in Section 4. Combustion emissions include NO_x, CO, PM, and NMOG. Various NMOG sources occur throughout the fuel transportation and distribution processes. The emissions correspond to values in Section 4.

Some second order fuel cycle emissions occur in the SoCAB and these are also included in the fuel cycle analysis. Second order emissions are the emissions associated with producing and distributing the fuel in the fuel cycle. For example, the fuel cycle emissions associated with hauling the diesel fuel used to transport gasoline are calculated.These values represent a very small fraction of the marginal emissions in urban areas.

Table A-38: Marginal NO_x Emissions in Urban Areas, Base Case (biodiesel to be completed)

Fuel Cycle Process	NOx (g/gal or g/kWh for electric)										
Fuel	**CARBOB**	**E100**	**RFG3**	**E85**	**E10**	**RFD**	**LPG**	**LPG NG**	**FTD**	**M100 NG**	**Electric**
Feedstock transport	0.0284	0.0000	0.0268	0.0043	0.0256	0.0285	0.0000	0.0000	0.0000	0.0000	0.000076
Refinery	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Fuel Transport	0.0000	0.0357	0.0020	0.0304	0.0036	0.0000	0.0207	0.0897	0.0263	0.0237	0.0000
Fuel Unloading	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Bulk Terminal	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Truck Spillage	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Truck Exhaust	—	—	0.0045	0.0045	0.0045	0.0049	0.0117	0.0117	0.0045	0.0045	0.0000
Truck Unloading	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Storage Tank Breathing	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vehicle Working Loss	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.000
Spillage	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.000
Total	—	—	0.033	0.039	0.034	0.033	0.032	0.101	0.031	0.028	0.000

Table A-39: Marginal NO_x Emissions in Urban Areas, Worst Case

Fuel Cycle Process	NOx (g/gal or g/kWh for electric)										
Fuel	**CARBOB**	**E100**	**RFG3**	**E85**	**E10**	**RFD**	**LPG**	**LPG NG**	**FTD**	**M100 NG**	**Electric**
Feedstock transport	0.0000	0.0000	0.0268	0.0043	0.0256	0.0285	0.0000	0.0000	0.0000	0.0000	0.0007
Refinery	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Fuel Transport	0.0284	0.2820	0.0161	0.2397	0.0282	0.0000	0.0207	0.0897	0.0263	0.0237	0.0000
Fuel Unloading	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Bulk Terminal	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Truck Spillage	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Truck Exhaust	—	—	0.0449	0.0449	0.0449	0.0494	0.1167	0.1167	0.0449	0.0449	0.0000
Truck Unloading	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Storage Tank Breathing	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vehicle Working Loss	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.000
Spillage	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.000
Total	—	—	0.088	0.289	0.099	0.078	0.137	0.206	0.071	0.069	0.001

Table A-40: Marginal PM Emissions in Urban Areas, Base Case

Fuel Cycle Process	PM (g/gal or g/kWh for electric)									
Fuel	CARBOB	E100	RFG3	E85	E10	RFD	LPG	LPG NG	FTD	M100 NG	Electric
Feedstock transport	0.0022	0.0000	0.0021	0.0003	0.0020	0.0022	0.0000	0.0000	0.0000	0.0000	0.000002
Refinery	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0032
Fuel Transport	0.0000	0.0040	0.0002	0.0034	0.0004	0.0000	0.0016	0.0013	0.0020	0.0020	0.0000
Fuel Unloading	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Bulk Terminal	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Truck Spillage	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Truck Exhaust	—	—	0.0002	0.0002	0.0002	0.0003	0.0006	0.0006	0.0002	0.0002	0.0000
Truck Unloading	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Storage Tank Breathing	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vehicle Working Loss	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.000
Spillage	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.000
Total	—	—	0.003	0.004	0.003	0.002	0.002	0.002	0.002	0.002	0.003

Table A-41: Marginal PM Emissions in Urban Areas, Worst Case

Fuel Cycle Process	PM (g/gal or g/kWh for electric)									
Fuel	CARBOB	E100	RFG3	E85	E10	RFD	LPG	LPG NG	FTD	M100 NG	Electric
Feedstock transport	0.0022	0.0000	0.0021	0.0003	0.0020	0.0022	0.0000	0.0000	0.0000	0.0000	0.0001
Refinery	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0038
Fuel Transport	0.0000	0.0040	0.0002	0.0034	0.0004	0.0000	0.0016	0.0013	0.0020	0.0020	0.0000
Fuel Unloading	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Bulk Terminal	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Truck Spillage	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Truck Exhaust	—	—	0.0024	0.0024	0.0024	0.0026	0.0062	0.0062	0.0024	0.0024	0.0000
Truck Unloading	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Storage Tank Breathing	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vehicle Working Loss	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.000
Spillage	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.000
Total	—	—	0.005	0.006	0.005	0.005	0.008	0.007	0.004	0.004	0.004

Table A-42: Marginal NMOG Emissions in Urban Areas, Base Case

Fuel Cycle Process	NMOG (g/gal or g/kWh for electric)										
Fuel	**CARBOB**	**E100**	**RFG3**	**E85**	**E10**	**RFD**	**LPG**	**LPG NG**	**FTD**	**M100 NG**	**Electric**
Feedstock transport	0.000	0.000	0.0000	0.0000	0.0000	0.0025	0.000	0.000	0.000	0.000	0.00006
Refinery	0.000	0.001	0.0001	0.0009	0.0001	0.0219	0.000	0.000	0.000	0.000	0.0070
Fuel Transport	0.0055	0.0032	0.0053	0.0036	0.0052	0.0000	0.0018	0.0103	0.0020	0.0020	0.000
Fuel unloading	0.0109	0.0000	0.0103	0.0016	0.0098	0.0045	0.2000	0.2000	0.0060	0.0070	0.000
Bulk terminal	0.0114	0.0030	0.0109	0.0043	0.0106	0.0014	0.0007	0.0007	0.0014	0.0030	0.000
Truck loading	—	—	0.0681	0.0681	0.0681	0.0090	0.0780	0.0780	0.0120	0.0140	0.000
Truck Spillage	—	—	0.0080	0.0080	0.0080	0.0080	0.0003	0.0003	0.0080	0.0080	0.000
Truck Exhaust	—	—	0.0019	0.0019	0.0019	0.002	0.001	0.001	0.002	0.002	0.000
Truck Unloading	—	—	0.0681	0.0681	0.0681	0.0090	0.0200	0.0200	0.0120	0.0140	0.000
Storage Tank Breathing	—	—	0.0304	0.0304	0.0304	0.0010	0.0000	0.0000	0.0010	0.0070	0.000
Vehicle Working Loss	—	—	0.173	0.173	0.173	0.011	0.080	0.080	0.014	0.077	0.000
Spillage	—	—	0.109	0.109	0.109	0.277	0.090	0.090	0.249	0.138	0.000
Total	—	—	0.485	0.468	0.484	0.347	0.472	0.481	0.307	0.272	0.007

Table A-43: Marginal NMOG Emissions in Urban Areas, Worst Case

Fuel Cycle Process	NMOG (g/gal or g/kWh for electric)										
Fuel	**CARBOB**	**E100**	**RFG3**	**E85**	**E10**	**RFD**	**LPG**	**LPG NG**	**FTD**	**M100 NG**	**Electric**
Feedstock transport	0.0025	0.0000	0.0023	0.0004	0.0022	0.0025	0.0000	0.0000	0.0000	0.0000	0.0007
Refinery	0.0000	0.0020	0.0001	0.0017	0.0002	0.0438	0.0000	0.0000	0.0000	0.0000	0.0140
Fuel Transport	0.0022	0.0322	0.0039	0.0277	0.0052	0.0000	0.0018	0.0103	0.0020	0.0020	0.0000
Fuel unloading	0.0690	0.0080	0.0655	0.0172	0.0629	0.0055	0.5000	1.5000	0.0070	0.0080	0.000
Bulk Terminal	0.3600	0.0063	0.3398	0.0594	0.3246	0.0036	0.0017	0.0017	0.0036	0.0063	0.0000
Truck Loading	—	—	0.1730	0.1730	0.1730	0.0110	2.0780	2.0780	0.0140	0.0160	0.000
Truck Spillage	—	—	0.0200	0.0200	0.0200	0.0200	0.0008	0.0008	0.0200	0.0200	0.0000
Truck Exhaust	—	—	0.0019	0.0019	0.0019	0.0020	0.0048	0.0048	0.0019	0.0019	0.0000
Truck Unloading	—	—	0.1530	0.1530	0.1530	0.0110	5.0000	5.0000	0.0140	0.0160	0.0000
Storage Tank Breathing	—	—	0.0300	0.0300	0.0300	0.0010	0.0000	0.0000	0.0010	0.0070	0.0000
Vehicle Working Loss	—	—	0.184	0.184	0.184	0.017	0.080	0.080	0.021	0.155	0.000
Spillage	—	—	0.383	0.383	0.383	0.383	0.091	0.091	0.313	0.182	0.000
Total	—	—	1.357	1.051	1.340	0.500	7.758	8.767	0.398	0.414	0.015

Table A-44: Marginal CO Emissions in Urban Areas, Base Case

Fuel Cycle Process	CO (g/gal or g/kWh for electric)										
Fuel	CARBOB	E100	RFG3	E85	E10	RFD	LPG	LPG NG	FTD	M100 NG	Electric
Feedstock transport	0.0034	0.0000	0.0032	0.0005	0.0030	0.0034	0.0000	0.0000	0.0000	0.0000	0.0005
Refinery	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Fuel Transport	0.0000	0.0030	0.0002	0.0025	0.0003	0.0000	0.0024	0.0167	0.0031	0.0028	0.0000
Fuel Unloading	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Bulk Terminal	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Truck Spillage	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Truck Exhaust	—	—	0.0064	0.0064	0.0064	0.0071	0.0350	0.0350	0.0064	0.0064	0.0000
Truck Unloading	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Storage Tank Breathing	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vehicle Working Loss	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.000
Spillage	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.000
Total	—	—	0.010	0.009	0.010	0.010	0.037	0.052	0.010	0.009	0.0005

Table A-45: Marginal CO Emissions in Urban Areas, Worst Case

Fuel Cycle Process	CO (g/gal or g/kWh for electric)										
Fuel	CARBOB	E100	RFG3	E85	E10	RFD	LPG	LPG NG	FTD	M100 NG	Electric
Feedstock transport	0.0034	0.0000	0.0032	0.0005	0.0030	0.0034	0.0000	0.0000	0.0000	0.0000	0.0007
Refinery	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Fuel Transport	0.0000	0.0524	0.0030	0.0445	0.0052	0.0000	0.0024	0.0167	0.0031	0.0028	0.0000
Fuel Unloading	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Bulk Terminal	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Truck Spillage	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Truck Exhaust	—	—	0.0064	0.0064	0.0064	0.0071	0.0167	0.0167	0.0064	0.0064	0.0000
Truck Unloading	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Storage Tank Breathing	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vehicle Working Loss	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.000
Spillage	—	—	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.000
Total	—	—	0.013	0.051	0.015	0.010	0.019	0.033	0.010	0.009	0.001

Toxic emissions were determined from the individual fuel cycle NMOG emission sources. The composition of toxic emissions was determined for various sources identified in Section 4. The ratio of toxics to NMOG was used to determine the toxic emissions for each step in the fuel cycle. While many fuel components such as methanol are poisionous or accutely toxic, toxic emisisons in this study only include compounds that are listed by ARB as toxic air contaminants. Toxics that occur from fuels and fuel combustion include:

- Benzene
- 1-3, butadiene
- formaldehyde
- acetaldehyde
- Polycyclic aromatic hydrocarbons (Toxic precursors)
- Diesel particulate

The for each toxic, the sum is determine for each source and the values are presented in the main report.

A.5.1 Analysis of Uncertainties

This section identifies the key uncertainties in fuel cycle emissions for each of the fuel options considered in this study, with emphasis given to the NMOG value. Several fuels are close the NMOG limit for the low fuel cycle emission portion of the PZEV allowance.

Figure A-2 shows the key parameters that affect NMOG emissions for gasoline fueled vehicles. The example shown here is for a mid-sized hybrid vehicles operating on RFG3. Spillage emissions are a significant source of marginal NMOG but estimates for these emissions has declined as ARB has. The range in spillage depends upon fuel tank size and the refueling spillage rate. This emission factor for spillage is based on the average vehicle; however, the spillage per gallon increases as fuel tank size decreases. Vehicles with improved fuel economy would have smaller fuel tanks and greater spillage per gallon. Based on limited data, fuel tank size is proportional to fuel economy; however, very efficient vehicles may tend to have somewhat greater range. Other parameters have a smaller effect on fuel cycle emissions.

Figure A-3 illustrates how total NMOG and spillage emissions are estimated to vary with fuel economy. Most of the fuel cycle emissions are constant per gallon dispensed so these emissions drop with fuel economy. Even though emission standards get a maximum spillage rate for fueling stations, it is likely that these emissions will not decrease as fuel economy is improved.

Figure A-2: Uncertain in Marginal NMOG Emissions from RFG3

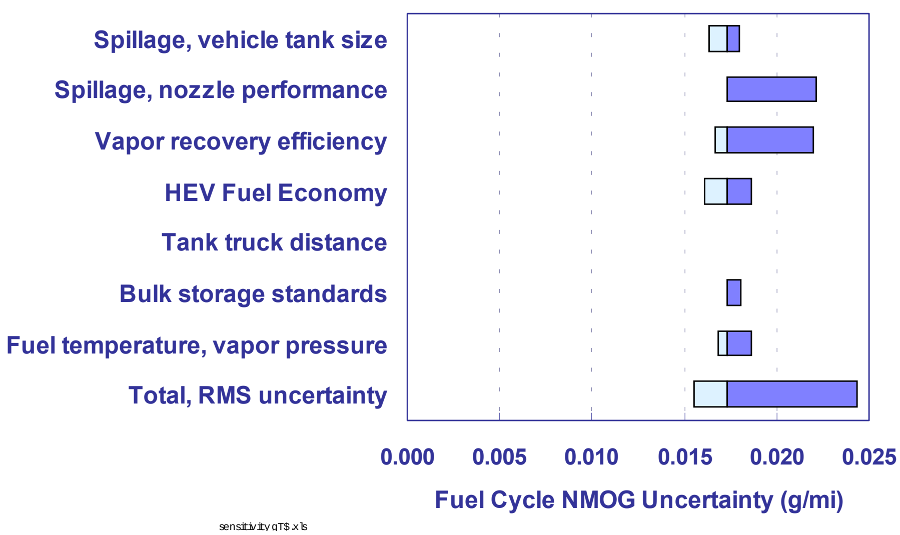
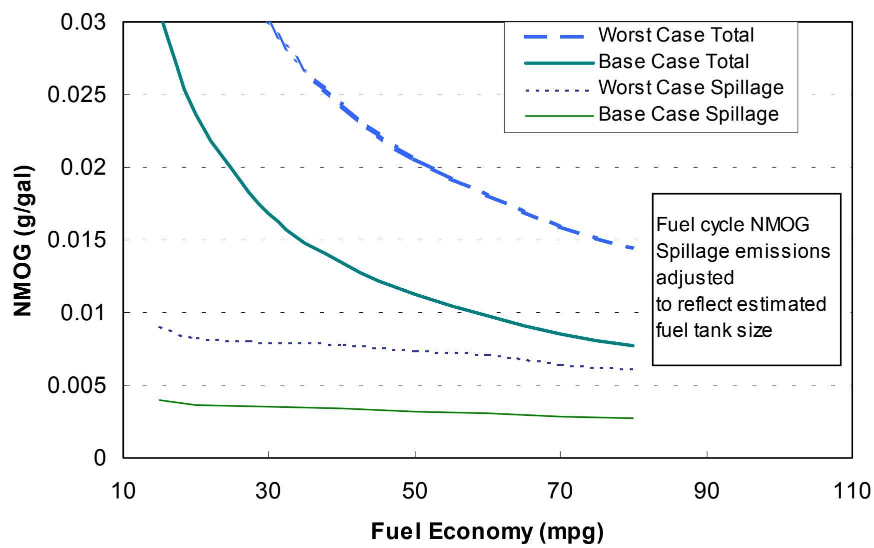


Figure A-3: Effect of Fuel Economy on Marginal NMOG Emissions from RFG3 Vehicles



A.6 Greenhouse Gas Emissions

GHG emissions were determined from energy inputs to the fuel cycle. The major assumptions that correspond to each fuel are indicated in the "modules" at the end of this section. Values from these modules are used to calculate GHG using both the Argonne National Laboratory GREET model and an in-house model.

Fuel cycle emissions were calculated for each unique "primary" fuel. These fuels include the following:

- CARB OB (blending componenet for RFG3)
- RFD
- Electric Power
- Ethanol from corn
- Methanol from natural gas
- LPG
- Natural gas (uncompressed)
- Rapeseed oil (to be completed)

Fuel cycle emissions are then determined for the fuels that are blended or processed from these primary fuels. Fuels that are simple blends include E85, E10, RFG3 (CARB OB plus 5.7 volume percent ethanol), biodiesel, and blended FTD/ diesel. Fuel cycle emissions are also calculated for fuels that require a combination of primary fuels in for their production. These fuels include CNG, ethanol from forest material, compressed hydrogen from steam reforming, and compressed hydrogen from electrolysis.

Table A-46 and Figure A-4 illustrate the energy inputs associated with primary fuels and the vehicle fuels considered in this study. (biodiesel to be added). The GHG emissions on a g/energy basis are shown in Figure A-5.

Figure A-5 illustrates the key parameters that affect GHG emissions. The GHG emissions associated with gasoline vehicles is relatively well defined as about 70 percent of the GHG emissions correspond to CO_2 from carbon in the fuel. The emissions per mile are less certain as they depend upon the vehicle fuel economy. The values in the figure correspond to a mid-size hybrid vehicle with an on-road fuel economy of 28 mpg. Vehicle fuel economy has the most significant impact on GHG emissions. The uncertainty represented in Figure A-5 represents the variability for a single type of vehicle and not the range fuel economy that can be expected for all vehicle classes. Other parameters that affect GHG emissions are also shown. The properties of crude oil correspond to the carbon content of the fuel and related CO_2 emissions. Interstingly, Figure A-5 illustrates that transportation distances and the type of oxygenate represent relatively small uncertainties when translated to GHG emissions.

Table A-46: Fuel Cycle Energy Inputs

Fuel	Vehicle (Fuel) Energy (MJ/MJ)			Fuel Cycle Energy (MJ/MJ)			Total (MJ/MJ)	
	Petroleum	Other Fossil Fuel	Non Fossil Fuel	Petroleum	Other Fossil Fuel	Non Fossil Fuel	Fuel	Fuel Chain
Electricity, CA — 100% NG	0.006	0.994	0.000	0.009	1.655	0.001	1.00	1.67
Electricity — US Avg. MIx	0.028	0.793	0.018	0.047	1.320	0.031	1.00	1.40
NG, Feedstock	0.002	0.015	0.015	0.004	0.024	0.025	1.00	0.05
CNG	0.002	0.030	0.016	0.004	0.050	0.026	1.00	0.08
LNG	0.007	0.087	0.017	0.012	0.144	0.029	1.00	0.19
LPG Petroleum NG mix	0.007	0.038	0.016	0.012	0.064	0.026	1.00	0.10
Methanol NG	0.015	0.307	0.022	0.026	0.511	0.037	1.00	0.57
FTD from NG	0.007	0.378	0.024	0.012	0.629	0.040	1.00	0.68
Ethanol Corn	0.056	0.312	0.754	0.093	0.519	1.256	1.00	0.61
CARB OB	0.060	0.096	0.005	0.099	0.160	0.008	1.00	0.27
RFD	0.050	0.062	0.002	0.084	0.104	0.004	1.00	0.19
RFG3	0.059	0.107	0.004	0.099	0.178	0.007	1.00	0.28
Ethanol Biomass	0.027	0.000	0.754	0.044	0.000	1.256	1.00	1.30
CNG, CA-power	0.002	0.035	0.015	0.004	0.058	0.025	1.00	0.09
cH2, CA-power	0.006	0.114	0.023	0.010	0.189	0.039	1.00	0.24

Figure A-4. Fuel Cycle Energy Inputs

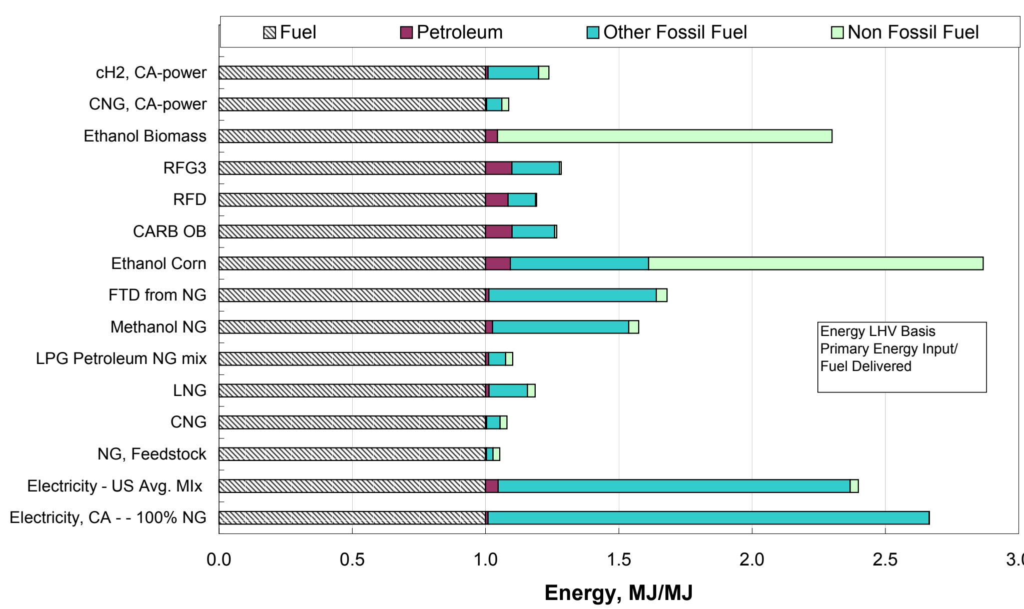


Figure A-5. GHG Emissions (Fuel Cycle Plus Fuel)

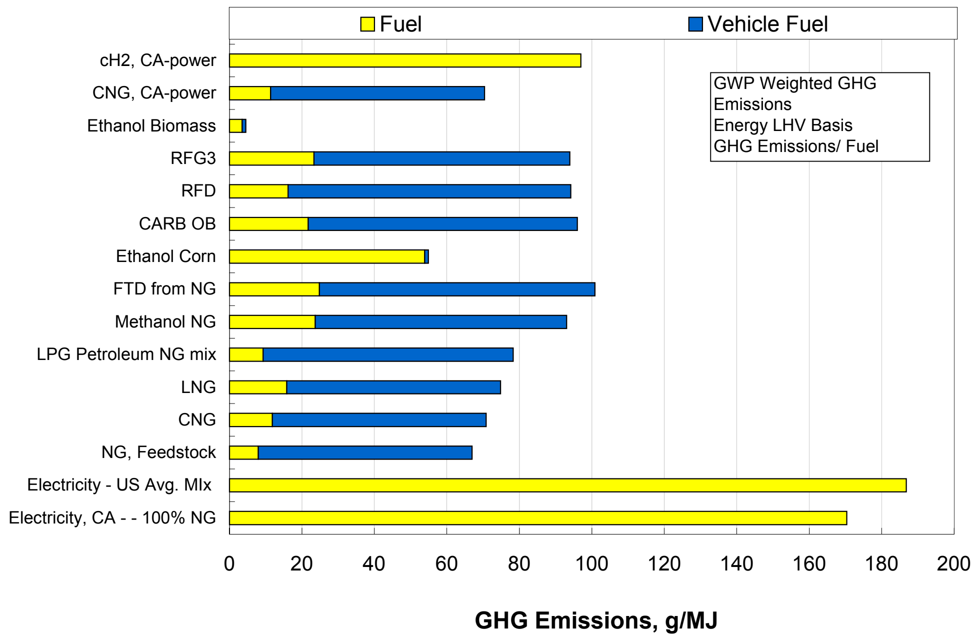
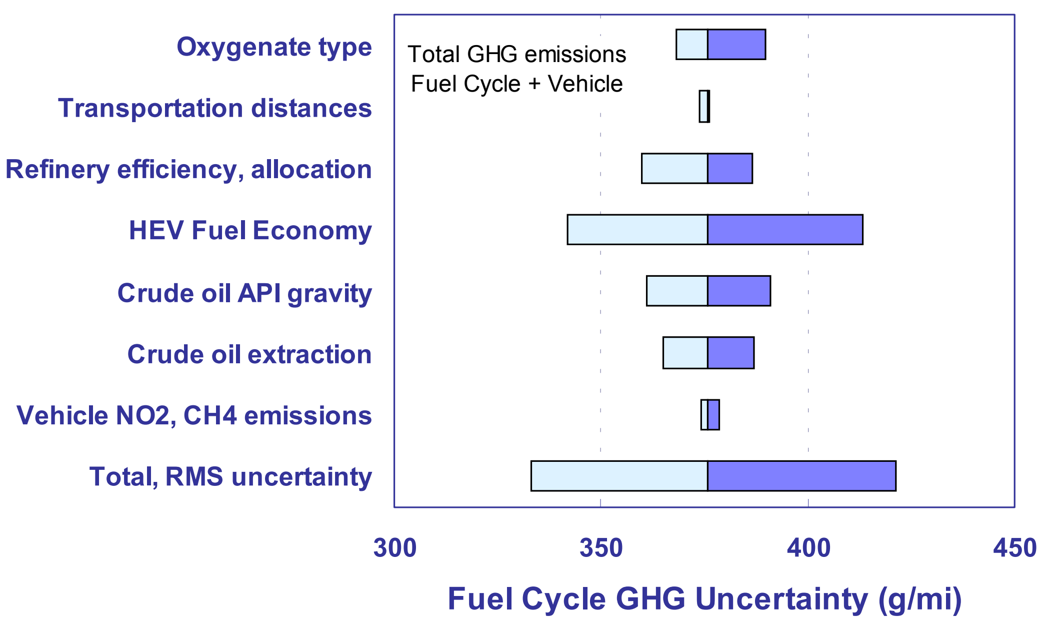


Figure A-6. Key Parameters that Affect GHG Emissions



sensitivity gT$.xls

A.6.1 Toxic Emissions

Toxic emissions correspond to marginal fuel cycle emission assumptions. Accordingly, the primary source of toxics are associated with tanker truck and rail car distribution, power generation, additional energy consumption related to clean diesel production, and vehicle fueling losses. Sources that are not expected to contribute to marginal emissions in California include average refinery emissions, methanol, FTD, and gas processing plant emissions (which occur outside of California) and coal power plants. Similarly, this study does not evaluate the effect of alternative fuel use on reduced tanker ship traffic and the potential for accidental releases. LFG and biomass based on ethanol plants could generally result in a reduction in toxic emissions depending on the source of waste feedstocks. The numerous feedstock alternatives are not evaluated here. An example is presented in a study on ethanol production (Perez 2001). Using feedstocks such as agricultural residue which would otherwise be burned results in a significant reduction in particulate emissions and potentially a reduction in toxics also.

California Assembly Bill AB 1807 created a comprehensive program to address adverse public health impacts from emissions of toxic substances to ambient air. Toxic air contaminants are an air pollutant that may cause or contribute to an increase in mortality or an increase in serious illness. A series of compounds were identified by ARB as toxic air contaminants, five of which are related to the combustion of fuels. They are 1,3-butadiene, benzene, formaldehyde, acetaldehyde, and diesel particulates. In addition, there are several compounds that are precursors to toxic air contaminates. Polycyclic aromatic hydrocarbons (PAH) and nitro-PAH are such precursors. Data on toxics were obtained from emission studies that include speciation data as well as the SoCAB inventory of toxics.

Toxic emissions and toxic precursors were estimated for engine exhaust, fuel, fuel vapor, natural gas, liquid petroleum gas, refinery emissions, pipeline compression engine emissions, and power plant emissions. They are given in terms of milligrams of toxics per gram of NMOG in Table A-47. These values are based on fuel properties and the 2001 ARB fuel cycle study (ARB 2001).

Table A-47: Toxic and Precursor Emissions Levels

Sources	Toxic (mg/g NMOG)					
	Benzene	1,3- Butadiene	Formaldehyde	Acetaldehyde	PAHs	N-PAHs
RFG vapor	6.11	0	0	0	67.4	ND
RFG liquid	17.9	0	0	0	295	ND
Diesel exhaust[a]	17.78	5.44	130	42.0	1.67	0.01
Diesel fuel, low aromatic[b]	0	0	0	0	100	ND
Diesel vapor, low aromatic[b]	0	0	0	0	9.36	ND
Methanol, ethanol	0	0	0	0	0	0
LPG	0	0	0	0	0	0
Refinery combustion[a]	ND	ND	124	ND	ND	ND
Power plant emissions[d]	ND	ND	844	ND	ND	ND
Natural gas IC engine exhaust[b]	2.98	1.19	130	3.0	0	0

[a]MATES data, SCAQMD 2000
[b]ARB speciation database, ARB 1993

Complete fuel chains are constructed from a combination of modules.

Fuel Chain	Fuel Chain Module				
	Extraction	Processing	Transport	Production	T S & D
CARB OB, Petroleum	P10,	—	T5	P11	T6
RFD, Petroleum	P10	—	T5	P15	T13
Methanol, NG	P1	P2	T1	P12	T8, T7
Ethanol, biomass	P18	T14	T10, T12	P19	T11
Ethanol, Corn	P13	T9	T10, T12	P14	T11
cH2, On-site NG SR	P1	P2	T1	P3	P5
cH2, On-site Electrolyzer	P20		T1	P7	—

To be updated for other fuel options biodiesel, LPG NG, CNG, LNG, LPG petroleum, FTD, Documentation of blends E10, E85, RFG3, biodiesel, FTD

APPENDIX Fuel Chain Modules

Feedstock Production and Processing

Module	Process
P1	Natural Gas Extraction
P2	Natural Gas Processing
P3	Hydrogen On-site Production & Compression
P4a	Hydrogen Central Production
P4b	Hydrogen On-site Compression, Tube-Trailer
P5	Hydrogen On-site Compression, Pipeline
P6	Hydrogen Central Liquefaction
P7	Hydrogen On-site Electrolysis
P8	Metal Hydride On-site Production & Compression
P9	Natural Gas Compression
P10	Petroleum Extraction
P11	Petroleum Refining to Gasoline
P12	Methanol from Natural Gas
P13	Corn Farming
P14	Ethanol from Corn
P15	Petroleum Refining to Diesel
P16	Biomass Chipping
P17	Biomass to Ethanol
P20	Electricity Generation
P21	Fischer Tropsch Diesel from NG
P22	Biomass Collection
P23	Ethanol from Biomass

Feedstock and Fuel Transport

Module	Process
T1	Natural Gas Pipeline
T2	Hydrogen Pipeline
T3	Liquid Hydrogen Transport
T4	Hydrogen Tube Trailer
T5	Petroleum Transport
T6	Gasoline Truck
T7	Methanol Truck
T8	Methanol Marine Transport
T9	Corn Truck
T10	Ethanol Marine
T11	Ethanol Truck
T12	Ethanol Train
T13	Diesel Truck
T14	Biomass Truck
T15	Power Transmission
T16	LPG Truck
T17	LNG Truck
T18	FTD Truck
T19	Biodiesel Truck
T20	FTD Marine

APPENDIX Module P1 Natural Gas Extraction

		Units	LHV, GJ	GJ/GJ primary product	Process Fuel Shares
INPUTS TO MODULE					
Throughput Fuel/Feedstock					
Natural Gas	37.79	GJ, HHV	34.01	1.000	97.42%
Process Fuels					
Natural Gas	848	scf	0.830	0.02	2.38%
Petroleum	0.08	gal	0.011	0.000	0.03%
Diesel	0.29	gal	0.039	0.001	0.11%
Electricity	3.13	kWh	0.011	0.000	0.03%
Gasoline	0.09	gal	0.011	0.000	0.03%
TOTAL INPUT				1.027	100%

OUTPUTS FROM MODULE				
Primary Products:				
Natural Gas	37.79	GJ, HHV	34.01	1.000
Secondary Products				
TOTAL OUTPUT				1.000
Module Efficiency, GJ-output/GJ-input				97.4%

Input Parameters		LHV
Natural Gas	928	Btu/scf
Petroleum	130,000	Btu/gal
Diesel	128,000	Btu/gal
Fuel Oil	140,000	Btu/gal
Gasoline	115,500	Btu/gal
Natural Gas	1.111	HHV/LHV
Conversion	947817	Btu/GJ
Conversion	278	kWh/GJ

References	
1. "Analysis and Integral Evaluation of Potential CO2-Neutral Fuel Chains," ADL Report, November 1999.	
Other Studies, MTE	
GREET, LHV	97%
ADL FORD Report, HHV	97%
NOVEM Report, HHV	95%

APPENDIX Module P2 Natural Gas Processing

		Units	LHV, GJ	GJ/GJ primary product	Process Fuel Shares
INPUTS TO MODULE					
Throughput Fuel/Feedstock					
Natural Gas	42.07	GJ, HHV	37.87	1.000	97.80%
Process Fuels					
Natural Gas	848	scf	0.830	0.02	2.14%
Electricity	5.56	kWh	0.020	0.001	0.05%
Gasoline	0.004	gal	0.000	0.000	0.00%
TOTAL INPUT			0.850	1.022	100.00%

OUTPUTS FROM MODULE				
Primary Products:				
Natural Gas	42.07	GJ, HHV	37.87	1.000
Secondary Products				
TOTAL OUTPUT				1.000
Module Efficiency, GJ-output/GJ-input				97.8%

Input Parameters		LHV
Natural Gas	928	btu/scf
Natural Gas	1.111	HHV/LHV
Gasoline	115,500	Btu/gal
Conversion	947817	Btu/GJ
Conversion	278	kWh/GJ

References	
1. "Analysis and Integral Evaluation of Potential CO2-Neutral Fuel Chains, ADL Report, November 1999.	
Other Studies, MTE	
GREET, LHV	97.5%
ADL FORD Report, HHV	97.1%
NOVEM Report, HHV	97.4%

APPENDIX Module P4a SMR Hydrogen Production, Central

		Units	LHV, GJ	GJ/GJ primary product
INPUTS TO MODULE				
Throughput Fuel/Feedstock				
Natural Gas	71.700	scf	0.070	1.26
Process Fuels				
Electricity	0.0100	kWh	3.60E-05	0.001
TOTAL INPUTS				1.261

OUTPUTS FROM MODULE				
Primary Products:				
Hydrogen	1.000	lb	0.056	1.00
Secondary Products				
TOTAL OUTPUTS				1.000
Module Efficiency, GJ-output/GJ-input				79.3%

Input Parameters		LHV
Natural Gas	928	Btu/scf
	47	MJ/kg
Hydrogen	52802	Btu/lb
	119.9	MJ/kg
Conversion	0.0036	GJ/kWh
Additional Conversions		
NG	MMBtu/kg-H2	0.147
electricity	kWh/kg-H2	0.022

References

1. ADL analysis

2. "Hydrogen production Plants: Emissions and Thermal Efficiency Analysis," Contadini, J.F., Diniz, C. V., Sperling, D. and Moore, R. M., Institute of Transportation Studies, Univ. of California, Davis, 2000

Comments:

modules, T-4 and T2

Other Studies,

GREET, LHV	73%	no energy credit
ADL FORD Report, HHV	83%	<---decentralized plant, no energy credit

APPENDIX Module P3, P4, P5 & P8 Hydrogen Production and Storage (On-Site, HYSIS Modeling)

Module Nos.		P3	P4b	P5	P8
Feedstock		**Natural Gas**	**Natural Gas**	**Natural Gas**	**Natural Gas**
Production		**Local SMR**	**Central SMR****	**Central SMR****	**Local SMR**
Purification		**PSA**			**PSA**
Transportation/On-site Storage		**3600 psi**	**Tube Trailer**	**Pipeline**	**100 psi**
On-board Storage		**cH2**	**cH2**	**cH2**	**MH**
On-site Energy Requirements from HYSYS					
Fuel in, kmol/hr		0.505			0.535
Fuel MW, g/mol		16.27			16.27
Fuel LHV, MJ/kg		48.83			48.83
Hydrogen out, kmol/hr		1.258	1.373	1.373	1.333
Production, kW		1.330			1.411
Purificaiton, kW		0.551			0.584
Storage, kW		6.692	3.462	8.435	1.610
Natural Gas Input	kg/hr	8.210			8.707
	MMBtu/hr, HHV	0.421			0.447
	GJ/hr, HHV	0.444			0.471
	MMBtu/hr, LHV	0.380			0.403
	GJ/hr, LHV	0.401			0.425
Power Input	kW	1.881			1.995
	GJ/hr	0.007			0.007
Hydrogen	kg/hr	2.541	2.773	2.773	2.692
	GJ/hr, HHV	0.361	0.394	0.394	0.383
	GJ/hr, LHV	0.305	0.332	0.332	0.323
Module Thermal Efficiency (Production)	**%**	**74.7%**	**See P4a****	**See P4a****	**74.7%**
Compression (Storage)	kW	6.692	3.462	8.435	1.610
	GJ/hr	0.02409	0.01246	0.03037	0.00580
Process Fuel Shares					
Natural Gas	%	93.5%	0.0%	0.0%	97.0%
Electricity	%	6.5%	100.0%	100.0%	3.0%
Module Thermal Efficiency (Compression)*	%	**92.7%**	**96.4%**	**91.6%**	**98.2%**

* - Central compression power is accounted for in the transportation modules

** - See Module P4a for Central SMR H2 Production

APPENDIX Module P6 Hydrogen Liquefaction

		Units	LHV, GJ	GJ/GJ primary product
INPUTS TO MODULE				
Throughput Fuel/Feedstock				
Hydrogen	300.00	tons	33,429	1.00
Process Fuels				
Power Requirements* (see liquefaction tal	4,477.20	MWh	16,118	0.482
TOTAL INPUTS				1.482

OUTPUTS FROM MODULE				
Primary Products:				
Hydrogen	300.00	tons	33,429	1.00
Secondary Products				
None				
TOTAL OUTPUTS				1.000
Module Thermal Efficiency, GJ-output/GJ-input				67.5%

Input Parameters		LHV
Hydrogen	0.056	GJ/lb
Hydrogen-gas	lb/scf	0.005189
Conversion	GJ/kWh	0.0036

References	
1. ADL internal estimate based on " Study of Large H2 Liquefaction Proces," Matsuda and Nagami, Nippon Sanso Corp, (see Liquefaction Reference)	
Other Studies, MTE	
GREET, LHV	70%
ADL FORD Report, HHV	NA
NOVEM Report, HHV	81%

APPENDIX Hydrogen Liquefaction Calculations

Hydrogen Claude Cycle
General Process Description
1. Compressed to 5 MPa
2. Cooled to 80 K
3. Ortho-Para Converter - converted to 47% para hydrogen
4. Further cooling
5. Liquefied at 0.1 MPa, 20.4K, by expansion (J-T) valve

Plant Basis	300	tons/day	12500	kg/hr
Total Power Required	106.6	MW	2558	MWh
NG Compressor Efficiency	40.00%			
Assume Power Mix				
Natural Gas	50%			
Electricity	50%			
Actual Natural Gas Input to Plant	133.3	MW	0.036	MMBtu/kg
(prior to efficiency losses)				
Electricity Input	53.3	MW	4.26	kWh/kg
Total Actual Power Input	4477	MWh/day		
	14.9	MWh/ton		
	7.5	kWh/lb		

Reference: Matsuda and Nagami, Nippon Sanso Corporation, 1997, (www. enaa.or.jp/WE-NET/ronbun/1997/e5/sanso1997.html)

APPENDIX Module P7 Hydrogen from Electrolyzer

		Units	LHV, GJ	GJ/GJ primary product
INPUTS TO MODULE				
Throughput Fuel/Feedstock				
Process Fuels				
Electricity	4.270	kWh	0.015	1.388
TOTAL INPUTS				1.388

OUTPUTS FROM MODULE				
Primary Products:				
Hydrogen	0.1988	lb	0.011	1.00
Secondary Products				
None				
TOTAL OUTPUTS				1.000
Module Efficiency				72.1%

Input Parameters		LHV
Hydrogen	Btu/scf	274
Hydrogen	Btu/lb	52802
Electrolysis power	kWh/Nm3	5.6
Conversion	kWh/GJ	0.0036

References	
1, Personal Communications with Stuart Energy, August 2001	
2. Teledyne Energy Systems, Specification Sheet ES-678, April 2000	
Other Studies, MTE	
ADL FORD Report, HHV	89%
NOVEM Report, HHV	80%

kWh/kg		**kWh/kg**
Electricity	Compressor	Total
47.35	2.634	50.0

APPENDIX Module P9 Natural Gas Compression

		Units	LHV, GJ	GJ/GJ primary product
INPUTS TO MODULE				
Throughput Fuel/Feedstock				
Natural Gas	100.00	scf	0.098	1.00
Process Fuels				
Natural Gas	6.50	scf	0.0064	0.065
Electricity	0.75	kWh	0.0027	0.028
TOTAL INPUTS				1.093

OUTPUTS FROM MODULE				
Primary Products:				
Natural Gas	100.00	scf	0.098	1.00
Secondary Products				
None				
TOTAL OUTPUTS				1.000
Module Efficiency, GJ-output/GJ-input				91.53%

Input Parameters		LHV
Natural Gas	928	Btu/scf
Electricity	0.015	kWh/scf
Conversion	0.0036	GJ/kWh

References	
1. "Analysis and Integral Evaluation of Potential CO2-Neutral Fuel Chains, " ADL Report, November 1999.	
2. ADL Internal Estimations	
NG ICE efficiency	40%
Other Studies, MTE	
GREET, LHV	97%
ADL FORD Report, HHV	94%
NOVEM Report, HHV	NA

APPENDIX Module P10 Petroleum Extraction

		Units	LHV, GJ	GJ/GJ primary product	Process Fuel Shares
INPUTS TO MODULE					
Throughput Fuel/Feedstock					
Petroleum	6.19	bbl	35.680	1.00	96.95%
Process Fuels					
Petroleum	9.1E-01	gal	1.2E-01	3.5E-03	0.34%
Diesel	0.70	gal	0.095	2.6E-03	0.26%
Heavy Fuel Oil	0.05	gal	0.007	2.0E-04	0.02%
Natural Gas	695.0	scf	0.680	1.9E-02	1.85%
Electricity	49.60	kWh	0.179	5.0E-03	0.49%
Gasoline	0.31	gal	0.038	1.1E-03	0.10%
TOTAL INPUTS			1.1E+00	1.032	100.00%

OUTPUTS FROM MODULE				
Primary Products:				
Petroleum	6	bbl	35.680	1
Secondary Products				
TOTAL INPUTS				1.000
Module Efficiency, GJ-output/GJ-input				96.9%

Input Parameters		LHV
Natural Gas	928	btu/scf
Petroleum	130,000	Btu/gal
Diesel	128,000	Btu/gal
Fuel Oil	140,000	Btu/gal
Gasoline	115,500	Btu/gal
Conversion	42.000	gal/barrel
Conversion	947817	Btu/GJ
Conversion	278	kWh/GJ

References	
1. "Analysis and Integral Evaluation of Potential CO2-Neutral Fuel Chains," ADL Report, November 1999.	
Other Studies, MTE	
GREET, LHV	98%
ADL FORD Report, HHV	96%
NOVEM Report, HHV	96%

APPENDIX Module P11 Petroleum Refining to Gasoline

		Units	LHV, GJ	GJ/GJ primary product	Process Fuel Shares
INPUTS TO MODULE					
Throughput Fuel/Feedstock					
Petroleum	0.15	bbl	0.870	1.03	87.3%
Process Fuel					
Petroleum Coke	8.6E-04	tons	1.9E-02	0.02	1.9%
Diesel	0.010	gal	0.001	0.00	0.1%
Heavy Fuel Oil	0.0685	gal	0.010	0.01	1.0%
LPG	0.0157	gal	0.001	0.00	0.1%
Natural Gas	62.5	scf	0.061	0.07	6.1%
Ethanol	0.000	gal	0.000	0.00	0.0%
Electricity	1.09	kWh	0.004	0.005	0.4%
Refinery Gas	31.00	scf	0.030	0.04	3.0%
TOTAL INPUT			1.3E-01	1.185	100.0%

OUTPUTS FROM MODULE				
Primary Products:				
FRFG2	7.11	gal	0.842	1.00
Secondary Products				
None				
TOTAL OUTPUT				1.000
Module Efficiency, GJ-output/GJ-input				84.4%

Input Parameters		LHV
Natural Gas	928	Btu/scf
Refinery Gas	928	Btu/scf
Petroleum	130,000	Btu/gal
Diesel	128,000	Btu/gal
Fuel Oil	140,000	Btu/gal
LPG	84,000	Btu/gal
FRFG	112,265	Btu/gal
Petroleum Coke	20,532,600	Btu/Ton
Ethanol	76,000	Btu/gal
Conversion	42.000	gal/barrel
Conversion	947817	Btu/GJ
Conversion	278	kWh/GJ

References

1. ADL internal estimate based on the MathPro report - " Analysis of the refining economics of California Phase 3 RFG ," Jan 5, 2000, submitted to CEC.
2. Assume ethanol to be the long-term oxygenate

Other Studies, MTE		
GREET, LHV	86%	
ADL FORD Report, HHV	87%	RFG
NOVEM Report, HHV	88%	conventional gasoline

APPENDIX Module P12 Methanol from Natural Gas

		Units	LHV, GJ	GJ/GJ primary product
INPUTS TO MODULE				
Throughput Fuel/Feedstock				
Natural Gas	93	scf	0.091	1.514
Process Fuels				
TOTAL INPUTS				1.514

OUTPUTS FROM MODULE				
Primary Products:				
Methanol	1	gal	0.060	1.00
Secondary Products				
Steam	0	Btu	0.000	0.00
TOTAL OUTPUTS			0.060	1.000
Module Thermal Efficiency, GJ-output/GJ-input				66.05%

Input Parameters		LHV
Natural Gas	928	Btu/scf
Methanol	57,000	Btu/gal
Steam Export	110,000	Btu/MMBtu
Conversion	947817	Btu/GJ
Conversion	278	kWh/GJ

References	
ADL/JT data - 68% efficiency, HHV basis	
Other Studies, MTE -- no steam credit	
ADL/JT New high cost ethanol plar	72%
ADL/JT New low cost ethanol plan	68%
GREET, LHV	70%
ADL FORD Report, HHV	62%

APPENDIX Module P13 Corn Farming

		Units	LHV, GJ	GJ/GJ primary product
INPUTS TO MODULE				
Throughput Fuel/Feedstock				
Corn	1.00	Bushel	0.354	1.00
Process Fuels				
Energy Use (process fuels+fertilizers)	17,091	Btu	0.018	0.051
TOTAL INPUTS				1.051

OUTPUTS FROM MODULE				
Primary Products:				
Corn	1.00	Bushel	0.354	1.00
Secondary Products				
TOTAL OUTPUTS			0.354	1.000
Module Efficiency, GJ-output/GJ-input				95.2%

Input Parameters		LHV
Ethanol yield	2.65	gal/bushel
Ethanol	76,000	Btu/gal
Corn Weight	56	lb/bushel
Corn Heat Value	6,000.00	Btu/lb
Conversion	947817	Btu/GJ
Conversion	278	kWh/GJ

REFERENCES		
1. Greet 1.5 - Transportation Fuel-Cycle Module, Vol. 1, Aug, 1999		
ANL Transportation TEchnology R&D CEnter, ANL/ESD-39		
2. ADI estimates		
Other Studies, MTE		
GREET, LHV	17,091	Btu/Bushel
ADL FORD Report, HHV	87%	
NOVEM Report, HHV	87%	

APPENDIX Module P14 Ethanol from Corn

		Units	LHV Btu	LHV, kJ
INPUTS TO MODULE				
Input Fuel				
Corn	2.65	gal/bushel		
Other Inputs				
Natural Gas	17,414	mmBtu/gal	12,689	16,733
Coal	17,414		12,689	16,733
Electricity	2.10	kWh/gal	7,165	7,559
Total			32,543	41,026
OUTPUTS FROM MODULE				
Primary Products:				
Ethanol	1	gal		76,000
Secondary Products				
DDGS, 21% protein				
Total				

INPUT PARAMETERS		
Corn	Btu/lb LHV	6000
Ethanol	Btu/gal LHV	76,000
	lb/gal	6.60
	kg/gal	2.996
Natural Gas	Btu/scfLHV	970
	lb/100scf	4.52
	kg/100scf	2.05
Steam Boiler Efficiency	Btu/Btu	80%
Electricity Conversion	Btu elec/kWh	3412
Power Plant Efficiency		38%
Energy Conversion	kJ/Btu	1.055
Portion of energy from electricity production available as steam	%	50%

References

1. 2.65 gal/bushel refers to yield in ProForma Cost Summary Report for Dry-Mill corn ethanol plant
2. 34,828 Btu at 80% boiler efficiency to produce 27,862 Btu of needed steam (carbonbalance.xls)
3. 2.1 kWh/gal is electricity input required in ProForma Cost Summary Report (carbonbalance.xls)

4. NREL, 1999. Environmental Life Cycle Implications of Fuel Oxygenate Production from California Biomass

Notes

1. Natural Gas is energy required for steam production. Cogen assumes that steam is also obtained from waste heat in electricity production
2. Other fuels could be used to provide steam energy. Assumption is that boiler efficiency is constant at 80%. Assumption also used in NREL, 1999 (see below).
3. Allocation of input energy to co-product not accounted for here
4. Cogen operation assumes that 50% of electricity-produced steam is used in production and therefore avoids additional natural gas
5. A good figure of merit for energy consumption is an on-site energy consumption value for steam production and a value for electricity consumption. Some other studies and the GREET model, however, use a combined figure of merit. As a result, we converted our electricity consumption into a Btu elec/gal value so the total could be input into GREET. In order to compare with other studies, this number must be converted to Btu thermal/gal. This conversion results in a value of 54,000 Btu/gal not including cogen, which is within the range of the other studies that also neglected cogen: approximately 48,000 Btu/gal to 63,000 Btu/gal.
Table of other studies' results is in CornModule.xls

APPENDIX Module P15 Petroleum Refining to RFD

		Units	LHV, GJ	GJ/GJ primary product	Process Fuel Shares
INPUTS TO MODULE					
Throughput Fuel/Feedstock					
Petroleum	0.16	bbl	0.922	1.050	93.55%
Process Fuel					
Petroleum Coke	1.9E-04	tons	4.0E-03	0.005	0.41%
Heavy Fuel Oil	0.0198	gal	0.003	0.003	0.30%
LPG	0.0047	gal	0.000	0.000	0.04%
Natural Gas	25.2	scf	0.025	0.028	2.50%
Electricity	0.31	kWh	0.001	0.001	0.11%
Refinery Gas	31.00	scf	0.030	0.035	3.08%
TOTAL INPUTS			6.3E-02	1.122	100.00%

OUTPUTS FROM MODULE				
Primary Products:				
Diesel	6.50	gal	0.878	1
Secondary Products				
TOTAL OUTPUTS				1.000
Module Efficiency, GJ-output/GJ-input				89.1%

Input Parameters		LHV
Natural Gas	928	Btu/scf
Refinery Gas	928	btu/scf
Petroleum	130,000	Btu/gal
Diesel	128,000	Btu/gal
Fuel Oil	140,000	Btu/gal
LPG	84,000	Btu/gal
Gasoline	115,500	Btu/gal
Petroleum Coke	20,532,600	Btu/Ton
Conversion	42	gal/barrel
Conversion	947817	Btu/GJ
Conversion	278	kWh/GJ

References

1. "Analysis and Integral Evaluation of Potential CO2-Neutral Fuel Chains," ADL Report, November 1999.

Comments

Other Studies, MTE		
GREET, LHV	87%	
ADL FORD Report, HHV	97%	conventional diesel
NOVEM Report, HHV	95%	

APPENDIX Module P16 Biomass Chipping

		Units	LHV, Btu	LHV, kJ	J/MJprimary product delivered
INPUTS TO MODULE					
Input Fuel					
Forest Material	1	BDT	17,000,000	17,935,000	1,000,000
Other Inputs					
Diesel	2.20	gal/BDT	281,600	297,088	16,565
Total			17,281,600		1,016,565
OUTPUTS FROM MODULE					
Primary Products:					
Forest Material	1	BDT	17,000,000	17,935,000	1,000,000
Secondary Products					
None					
Total					1,000,000
Module Efficiency, GJ-output/GJ-input					98.4%

INPUT PARAMETERS		
Forest Material	Btu/dry-lb	8500
Diesel	Btu/gal LHV	128000
	lb/gal	7.14
	kg/gal	3.24

REFERENCES

1. Chipping fuel requirement within range of various studies
2. QLG Feasibility Study suggests a cost of $30-40/BDT for this processing

COMMENTS

1. Assume heat rate of biomass is 8500 Btu/dry lb

Other Studies, MTE		
GREET, LHV	234,770	gal diesel/BDT
ADL FORD Report, HHV		
NOVEM Report, HHV		

APPENDIX Module P17 Ethanol from Biomass

		Units	LHV Btu	LHV, kJ
INPUTS TO MODULE				
Input Fuel				
Forest Material	77.70	gal/BDT		
Other Inputs				
Natural Gas	0	mmBtu/gal	0	0
Electricity	0.00	kWh/gal	0	0
Diesel	1.45	gal/1000 gal	186	176
Total				
OUTPUTS FROM MODULE				
Primary Products:				
Ethanol	1	gal	76,000	72,038
Secondary Products				
Electricity	2.066	kWh thermal/gal	18,594	17,625
Total				

INPUT PARAMETERS		
Biomass	Btu/dry-lb	8500
Ethanol	Btu/gal LHV	76,000
	lb/gal	6.60
	kg/gal	2.996
Diesel	Btu/gal LHV	128000
Electricity Conversion	Btu/kWh	9000
Energy Conversion	kJ/Btu	1.055

References

1. ProForma Cost Summary Report (calculations in carbonbalance.xls)
2. Scenario is midterm ethanol plant using lignin to provide energy inputs (Case 34)

Notes

1. Lignin by-product is combusted to produce steam and excess electricity
2 No marketable co-products are accounted for

APPENDIX Module P20 Electricity Generation

		Units	LHV, GJ	GJ/GJ primary product	Process Fuel Shares
INPUTS TO MODULE					
Throughput Fuel/Feedstock					
Coal	5,341	Btu	5.6E-03	1.57	54.0%
Oil	79	Btu	8.3E-05	0.02	0.8%
Natural Gas	1,309	Btu	1.4E-03	0.38	21.1%
Nuclear	1,244	Btu	1.3E-03	0.36	12.4%
Other (Renewables)	998	Btu	1.1E-03	0.29	11.7%
TOTAL INPUT	8,971	Btu	9.5E-03	2.6E+00	

OUTPUTS FROM MODULE				
Primary Products:				
Electricity	1.00	kWh	0.004	1.00
Secondary Products				
None				
TOTAL OUTPUT				1.000
Module Efficiency, GJ-output/GJ-input				38.03%

Input Parameters		LHV
Conversion	3,412	Btu/kWh
Conversion	947817	Btu/GJ
Conversion	278	kWh/GJ
U.S. AVERAGE ELECTRICITY GENERATION MIX		
REF: GREET		
	%	Efficiency, %
COAL	54.0%	34.5%
OIL	0.8%	34.5%
NG*	21.1%	55.0%
NUCLEAR	12.4%	34.0%
OTHER**	11.7%	40.0%
* -- Combined Cycle		
** -- Industry Experience		

APPENDIX Module P21 Fischer Tropsch Diesel from NG

		Units	LHV, GJ	GJ/GJ primary product
INPUTS TO MODULE				
Throughput Fuel/Feedstock				
Natural Gas	205	scf	0.201	1.601
Process Fuels				
TOTAL INPUTS				1.601

OUTPUTS FROM MODULE				
Primary Products:				
Fischer Tropsch Diesel	1	gal	0.125	1.00
Secondary Products				
Steam	0	Btu	0.000	0.00
TOTAL OUTPUTS			0.125	1.000
Module Thermal Efficiency, GJ-output/GJ-input				62.45%

Input Parameters		LHV
Natural Gas	928	Btu/scf
Fischer Tropsch Diesel	118,800	Btu/gal
Steam Export	110,000	Btu/MMBtu
Conversion	947817	Btu/GJ
Conversion	278	kWh/GJ

References	
ADL/JT data - 68% efficiency, HHV basis	
Other Studies, MTE -- no steam credit	
ADL/JT New high cost ethanol plar	72%
ADL/JT New low cost ethanol plant	68%
GREET, LHV	70%
ADL FORD Report, HHV	62%

APPENDIX Module P22 Biomass Collection

		Units	LHV, GJ	GJ/GJ primary product
INPUTS TO MODULE				
Throughput Fuel/Feedstock				
Corn Stover	1.00	BDT	15.071	1.00
Process Fuels				
Diesel	181,665	Btu/BDT	0.192	0.013
TOTAL INPUTS				1.013

OUTPUTS FROM MODULE				
Primary Products:				
Corn Stover	1.00	BDT	15.071	1.00
Secondary Products				
None				
TOTAL OUTPUTS			15.071	1.000
Module Thermal Efficiency, GJ-output/GJ-input				98.7%

Input Parameters		LHV
Ethanol yield	95.00	gal/bdt
Ethanol	76,000	Btu/gal
Corn Weight	56	wet lb/bushel
Corn Stover/Corn ratio	1	lb/lb
Corn Stover Heat Value	7,143	Btu/dry-lb
Conversion	947817	Btu/GJ
Conversion	278	kWh/GJ

REFERENCES

1. Greet 1.5 - Transportation Fuel-Cycle Module, Vol. 1, Aug, 1999
ANL Transportation TEchnology R&D CEnter, ANL/ESD-39
2. Corn Stover Collection Project, DOE, 1998.
3. Estimate that diesel required for collecting stover is equal to one quarter of diesel
used in corn farming (17091Btu/Bushel)

Other Studies, MTE		
GREET, LHV	17,091	Btu/Bushel
ADL FORD Report, HHV	87%	
NOVEM Report, HHV	87%	

APPENDIX Module P23 Ethanol from Biomass

		Units	LHV Btu	LHV, kJ
INPUTS TO MODULE				
Input Fuel				
Corn Stover	95.00	gal/BDT		
Other Inputs				
Natural Gas	0	mmBtu/gal	0	0
Electricity	0.00	kWh/gal	0	0
Diesel	1.45	gal/1000 gal	186	176
Total				
OUTPUTS FROM MODULE				
Primary Products:				
Ethanol	1	gal	76,000	72,038
Secondary Products				
Electricity	2.066	kWh thermal/gal	18,594	17,625
Total				

INPUT PARAMETERS		
Ethanol	Btu/gal LHV	76,000
	lb/gal	6.60
	kg/gal	2.996
Diesel	Btu/gal LHV	128000
Electricity Conversion	Btu/kWh	9000
Energy Conversion	kJ/Btu	1.055

References

1. Energy inputs based on ethanol from woody material in ProForma Cost Summary Report (calculations in carbonbalance.xls)
2. Scenario is midterm ethanol plant using lignin to provide energy inputs (Case 34)
3. Yield of 95 gal/ton based on 80gal/wet ton estimated as initial corn stover yields in DOE Corn Stover Collection Project, 1998. With mature conversion technology, up to 130 gal/ton

Notes

4. Lignin by-product is combusted to produce steam and excess electricity

APPENDIX Module T1 Natural Gas Transport, Pipeline

		Units	LHV, GJ	GJ/GJ primary product delivered
INPUTS TO MODULE				
Throughput Fuel/Feedstock				
Natural Gas	1,000,000	scf	9.79E+02	1.000
Process Fuel				
Electric + NG Power	1,575	hp-hr/MMscf	4.23E+00	0.004
TOTAL INPUTS				1.004

OUTPUTS FROM MODULE				
Primary Products:				
Natural Gas	1,000,000	scf	9.79E+02	1.000
Secondary Products				
None				
TOTAL OUTPUTS				1.000
Module Efficiency, GJ-output/GJ-input				99.57%

INPUT PARAMETERS		
Natural Gas		
Heating Value, LHV	Btu/scf	928
Pipeline Length	mi	1000
NG Compressor ICE efficiency factor		0.4
Use Factor	hp-hr/MMscf/mi	1.575
Conversion Factor	kJ/hp-hr	2684.52

REFERENCES	
1. Evaluation of Fuel-Cycle Emissions on a Reactivity Basis, Vol. 1, Main Report, Sep 1996	
Prepared for CARB by Acurex Environmental	
Other Studies, MTE	
GREET, LHV	97.0%
ADL FORD Report, HHV	97.4%
NOVEM Report, HHV	99.9%

APPENDIX Module T2 Hydrogen Transport, Pipeline

		Units	LHV, GJ	GJ/GJ primary product delivered
INPUTS TO MODULE				
Throughput Fuel/Feedstock				
Hydrogen	1,000,000	scf	2.89E+02	1
Process Fuel				
NG + Electricity	1.75	GJ	1.75E+00	0.01
TOTAL INPUTS				1.01
OUTPUTS FROM MODULE				
Primary Products:				
Hydrogen	1,000,000	scf	2.89E+02	1.00
Secondary Products				
None				
TOTAL OUTPUTS				1.00
Module Efficiency, GJ-output/GJ-input				99.40%

INPUT PARAMETERS		
Hydrogen		
Heating Value, LHV	Btu/scf	274
	Btu/lb	52802
	lb/MMscf	5189.20
	kg/MMscf	2353.38
NG, LHV	Btu/scf	928
Process Fuel Power	GJ/MMscf	1
Natural Gas ICE Efficiency Factor		0.4
NG Process Fuel Share		50%
Electricity Process Fuel Share		50%
Conversion	GJ/MMBtu	1.055
Conversion	GJ/kWh	0.0036
Additional Conversions		
NG Process Fuel Share	MMBtu/kg	0.0005
Electricity Process Fuel Share	kWh/kg	0.0591

REFERENCES

1. "Analysis and Integral Evaluation of Potential CO2-Neutral Fuel Chains, NOVEM, November 1999.

COMMENTS

1. Assumes a 50-mile long pipeline

Other Studies, MTE		
GREET, LHV	97.0%	
ADL FORD Report, HHV	99.2%	100-mile pipeline
NOVEM Report, HHV	99.6%	50-mile pipeline

APPENDIX Module T3 Liquid HydrogenTransport, Truck

		Units	LHV, GJ	GJ/GJprimary product delivered
INPUTS TO MODULE				
Throughput Fuel/Feedstock				
LH2	3,370	kg/truck	407	1.00
Process Fuels				
Diesel	18.18	gal (round trip)	2.5	0.01
TOTAL INPUTS				1.01

OUTPUTS FROM MODULE				
Primary Products:				
LH2	7,800	gal	407	1.00
Secondary Products				
None				
Total				1
Module Efficiency, GJ-output/GJ-input				99.4%

INPUT PARAMETERS		
Average Truck	mi/gal	5.5
Average One-way Trip Distance	mi	50
LH2	Btu/gal LHV	30100
	lb/gal	0.580
	kg/gal	0.263
Diesel	Btu/gal LHV	128000
	lb/gal	7.14
	kg/gal	3.24

References	
1. Refinement of Selected Fuel-Cycle Emissions Analyses, Vol. 1 Final Report, Dec 2000	
Prepared for CARB and SCAQMD, FR-00-101 by Arthur D. Little	
2. Hydrogen - The Coming Fuel, Linde Presentation, INTERTECH, Nice, France, May 2001	
Other Studies, MTE	
GREET, LHV	95.0%
NOVEM Report, HHV	99.9%

APPENDIX Module T4 Hydrogen Transport, Tube Trailer

		Units	LHV, GJ	GJ/GJprimary product delivered
INPUTS TO MODULE				
Throughput Fuel/Feedstock				
Hydrogen	530	kg	68.01	1.000
Process Fuel				
NG + Electricity (Ref:2)	2,384	kWh	8.6	0.126
Diesel	20.00	gal (round trip)	2.7	0.040
TOTAL INPUTS				1.166

OUTPUTS FROM MODULE				
Primary Products:				
Hydrogen	530	kg	68.01	1.000
Secondary Products				
None				
TOTAL OUTPUTS				1.000
Module Efficiency, GJ-output/GJ-input				85.8%

INPUT PARAMETERS		
Average Truck Fuel Usage	mi/gal	5
Average One-way Trip Distance	mi	50
Compression Power	kWh/GJ	35.06
Hydrogen	kg/kmol	2.016
	Btu/lb, LHV	52802
	Btu/kg, LHV	116428
	Btu/kmol, LHV	245198
	GJ/kmol, LHV	0.2587
	Btu/scf, LHV	274
Diesel	Btu/gal LHV	128000
	lb/gal	7.14
	kg/gal	3.24
conversion	kWh/GJ	278

References	
1. Evaluation of Fuel-Cycle Emissions on a REactivity Basis, Vol. 1, Main Report, Sep 1996 Prepared for CARB by Acurex Environmental	
2. ADL see tab "H2 Compression"	
Other Studies, MTE	
GREET, LHV	97.0%

Hydrogen Compression - Tube Trailer

Central SMR, Hydrogen Compression for Tube Trailer				
Hydrogen	1.373	kmol/hr	0.337	GJ/hr
Required Power	6.84	kW_e	0.025	GJ/hr
Power Shares				
Natural Gas	50%			
Electric Motor Efficiencv	95%			
IC Engine Efficiency	40%	LHV		
Actual Input Compressor	8.6	kW_{th}	0.011	MMBtu/kg
Electricity	50%			
	3.25	kW	1.174	kWh/kg
Input				
Compressor	11.8	kW	0.042	GJ/hr
	35.061	kWh/GJ		
Output				
Hydrogen	1.26	kmol/hr	0.337	GJ/hr
Module Thermal Efficiency			88.8%	
Primary Energy	GJ/kg	0.015		

Thermal Data			**LHV**					
Hydrogen	274	Btu/scf	232328	Btu/kmol	52802	Btu/lb	0.0051892	lb/scf

Data Conversion to GREET Input						
Hydrogen, INput	292734	Btu/hr	308834	kJ/hr	1	GJ/GJ-product
Electricity	22848	Btu/hr	24104	kJ/hr	0.078	GJ/GJ-product
Hydrogen, Output	292734	Btu/hr	308834	kJ/hr	1	GJ/GJ-product
Module Thermal Efficiency					92.76%	

APPENDIX Module T5 Petroleum Transport, Pipeline&Marine

		Units	LHV, GJ	GJ/GJprimary product delivered
INPUTS TO MODULE				
Input Fuel				
Petroleum	142,500	DWT	6.11E+06	1.000
Other Inputs				
Bunker Fuel	3,847,500	kg (round trip)	1.64E+05	0.027
Diesel	2,243	gal	3.03E+02	0.000
Total				1.027

OUTPUTS FROM MODULE				
Primary Products:				
Petroleum	142,500	DWT	6.11E+06	1.000
Secondary Products				
Total				1.000
Module Efficiency, GJ-output/GJ-input				97.38%

INPUT PARAMETERS		
Petroleum		
Density	kg/gal	3.2
Energy Content	Btu/gal, LHV	130000
	Btu/kg	40625
Bunker Fuel		
Tanker Fuel Consumption	kg/ton-mi	0.0018
Average One-way Trip Distance	mi	7500
Bunker Fuel	Btu/kg	40350
Tanker Load Efficiency		0.95
Diesel		
In-port use factor	kg/DWT	0.051
Energy Content	Btu/gal, LHV	128000
Diesel Density	kg/gal	3.24

REFERENCES	
1. Evaluation of Fuel-Cycle Emissions on a REactivity Basis, Vol. 1, Main Report, Sep 1996 Prepared for CARB by Acurex Environmental	
Other Studies, MTE	
GREET, LHV	99.5%

APPENDIX Module T6 Gasoline Transport, Truck

		Units	LHV, GJ	GJ/GJprimary product delivered
INPUTS TO MODULE				
Input Fuel				
Gasoline	7,800	gal	950	1.000
Other Inputs				
Diesel	20.00	gal (round trip)	3	0.003
Total				1.003

OUTPUTS FROM MODULE				
Primary Products:				
Gasoline	7,800	gal	950	1.000
Secondary Products				
Total				1.000
Module Efficiency, GJ-output/GJ-input				99.7%

INPUT PARAMETERS		
Average Truck Fuel Usage	mi/gal	5
Average One-way Trip Distance	mi	50
Gasoline	Btu/gal LHV	115500
Diesel	Btu/gal LHV	128000
	lb/gal	7.14
	kg/gal	3.24

REFERENCES	
1. Evaluation of Fuel-Cycle Emissions on a REactivity Basis, Vol. 1, Main Report, Sep 1996 Prepared for CARB by Acurex Environmental	
Other Studies, MTE	
GREET, LHV	98.5%

APPENDIX Module T7 Methanol Transport, Truck

		Units	LHV, GJ	GJ/GJprimary product delivered
INPUTS TO MODULE				
Input Fuel				
Methanol	7,800	gal	469	1.000
Other Inputs				
Diesel	20.00	gal (round trip)	3	0.006
Total				1.006

OUTPUTS FROM MODULE				
Primary Products:				
Methanol	7,800	gal	469	1.000
Secondary Products				
Total				1.000
Module Efficiency, GJ-output/GJ-input				99.4%

INPUT PARAMETERS		
Average Truck	mi/gal	5
Average One-way Trip Distance	mi	50
Methanol	Btu/gal LHV	57000
	lb/gal	6.60
	kg/gal	2.996
Diesel	Btu/gal LHV	128000
	lb/gal	7.14
	kg/gal	3.24

References

1. Refinement of Selected Fuel-Cycle Emissions Analyses, Vol. 1 Final Report, Dec 2000
Prepared for CARB and SCAQMD, FR-00-101 by Arthur D. Little

APPENDIX Module T8 Methanol Transport, Marine

		Units	LHV, GJ	GJ/GJprimary product delivered
INPUTS TO MODULE				
Input Fuel				
Methanol	142,500	DWT	2,594,797	1.0000
Other Inputs				
Bunker Fuel	3,847,500	kg (round trip)	163,785	0.0631
Diesel	2,243	gal (In-port)	303	0.0001
Total				1.0632

OUTPUTS FROM MODULE				
Primary Products:				
Methanol	142,500	DWT	2,594,797	1.0000
Secondary Products				
None				
Total				1.0000
Module Efficiency, GJ-output/GJ-input				94.05%

INPUT PARAMETERS		
Bunker Fuel		
Tanker Fuel Consumption	kg/ton-mi	0.0018
Average One-way Trip Distance	mi	7500
Bunker Fuel	Btu/kg	40350
Tanker Load Efficiency		0.95
Diesel		
In-port use factor	kg/DWT	0.051
Energy Content	Btu/gal, LHV	128000
Diesel Density	kg/gal	3.24
Methanol		
	Btu/gal LHV	57000
	lb/gal	6.60
	gal/DWT	303
	kg/gal	2.996

REFERENCES

1. Evaluation of Fuel-Cycle Emissions on a REactivity Basis, Vol. 1, Main Report, Sep 1996
Prepared for CARB by Acurex Environemntal

APPENDIX Module T9 Corn Transport, Truck

		Units	LHV, GJ	GJ/GJ primary product
INPUTS TO MODULE				
Input Fuel				
Corn-ethanol	1.00	Bushel	0.414	1.00
Other Inputs				
Energy Use forTransportation	4,897	Btu	0.005	0.012
Total				1.012

OUTPUTS FROM MODULE				
Primary Products:				
Corn-ethanol	1.00	Bushel	0.414	1.00
Secondary Products				
None				
Total			0.414	1.000
Module Efficiency, GJ-output/GJ-input				98.8%

Input Parameters		LHV
Ethanol yield	2.65	gal/bushel
Ethanol	76,000	Btu/gal
Corn	7,000	Btu/lb
	56	lb/Bushel
Corn Stover	95	gal/BDT
Conversion	947817	Btu/GJ
Conversion	278	kWh/GJ

References

1. Greet 1.5 - Transportation Fuel-Cycle Module, Vol. 1, Aug, 1999
ANL Transportation TEchnology R&D CEnter, ANL/ESD-39
2. ADL industry experience

APPENDIX Module T10 Ethanol Transport, Marine

		Units	LHV, GJ	GJ/GJprimary product delivered
INPUTS TO MODULE				
Input Fuel				
Ethanol	142,500	DWT	3.61E+06	1.000
Other Inputs				
Bunker Fuel	1,795,500	kg (round trip)	7.64E+04	0.021
Diesel	2,243	gal (In-port)	3.03E+02	0.000
Total				1.021

OUTPUTS FROM MODULE				
Primary Products:				
Ethanol	142,500	DWT	3.61E+06	1.000
Secondary Products				
None				
Total				1.000
Module Efficiency, GJ-output/GJ-input				97.92%

INPUT PARAMETERS		
Bunker Fuel		
Tanker Fuel Consumption	kg/ton-mi	0.0018
Average One-way Trip Distance	mi	3500
Bunker Fuel	Btu/kg	40350
Tanker Load Efficiency		0.95
Diesel		
In-port use factor	kg/DWT	0.051
Energy Content	Btu/gal, LHV	128000
Diesel Density	kg/gal	3.24
Ethanol		
Heat Content	Btu/gal LHV	76000
Density	kg/gal	2.996
Density	lb/gal	6.60

REFERENCES

1. Evaluation of Fuel-Cycle Emissions on a Reactivity Basis, Vol. 1, Main Report, Sep 1996
Prepared for CARB by Acurex Environemntal

APPENDIX Module T11 Ethanol Transport, Truck

		Units	LHV, GJ	J/MJprimary product delivered
INPUTS TO MODULE				
Input Fuel				
Ethanol	7,800	gal	625	1.000
Other Inputs				
Diesel	20.00	gal (round trip)	3	0.004
Total				1.004

OUTPUTS FROM MODULE				
Primary Products:				
Ethanol	7,800	gal	625	1.000
Secondary Products				
Total				1.000
Module Thermal Efficiency				99.6%

INPUT PARAMETERS		
Average Truck Fuel Usage	mi/gal	5
Average One-way Trip Distance	mi	50
Ethanol	Btu/gal, LHV	76000
Diesel	Btu/gal LHV	128000
	lb/gal	7.14
	kg/gal	3.24

REFERENCES
1. Evaluation of Fuel-Cycle Emissions on a REactivity Basis, Vol. 1, Main Report, Sep 1996 Prepared for CARB by Acurex Environmental

APPENDIX Module T12 Ethanol Transportation, Train

		Units	LHV, GJ	GJ/GJprimary product delivered
INPUTS TO MODULE				
Throughput Fuel/Feedstock				
Ethanol	30,000	gal	2,405	1.000
Process Fuels				
Diesel	53.57	gal (round trip)	7	0.003
Total				1.003

OUTPUTS FROM MODULE				
Primary Products:				
Ethanol	30,000	gal	2,405	1.000
Secondary Products				
Total				1.000
Module Efficiency, GJ-output/GJ-input				99.7%

INPUT PARAMETERS		
Average Train Fuel Usage	gal/1000-ton mi	87.2
Average One-way Trip Distance	mi	500
Ethanol Transport Factor		0.25
Ethanol	Btu/gal, LHV	76000
Diesel	Btu/gal LHV	128000
	lb/gal	7.14
	kg/gal	3.24

REFERENCES

1. Evaluation of Fuel-Cycle Emissions on a REactivity Basis, Vol. 1, Main Report, Sep 1996
Prepared for CARB by Acurex Environmental

APPENDIX Module T13 Diesel Transport, Truck

		Units	LHV, GJ	GJ/GJprimary product delivered
INPUTS TO MODULE				
Input Fuel				
Diesel	7,800	gal	1,053	1.000
Other Inputs				
Diesel	20.00	gal (round trip)	3	0.003
Total				1.003

OUTPUTS FROM MODULE				
Primary Products:				
Diesel	7,800	gal	1,053	1.000
Secondary Products				
None				
Total				1.000
Module Efficiency, GJ-output/GJ-input				99.7%

INPUT PARAMETERS		
Average Truck Fuel Usage	mi/gal	5
Average One-way Trip Distance	mi	50
Gasoline	Btu/gal LHV	115500
Diesel	Btu/gal LHV	128000
	lb/gal	7.14
	kg/gal	3.24

REFERENCES	
1. Evaluation of Fuel-Cycle Emissions on a Reactivity Basis, Vol. 1, Main Report, Sep 1996	
Prepared for CARB by Acurex Environmental	
Other Studies, MTE	
GREET, LHV	98.6%

APPENDIX Module T14 Biomass Transport, Truck

		Units	LHV, Btu	LHV, kJ	J/MJprimary product delivered
INPUTS TO MODULE					
Input Fuel					
Forest Material (chipped)	1	BDT	8,500	8,968	1,000,000
Other Inputs					
Diesel	1.57	gal/BDT (round trip)	201,143	212,206	23,663,866
Total			209,643		24,663,866
OUTPUTS FROM MODULE					
Primary Products:					
Ethanol	1	BDT	8,500	8,968	1,000,000
Secondary Products					
None					
Total					1,000,000

INPUT PARAMETERS		
Average Truck Fuel Usage	mi/gal	4
One way distance for 40 mill gal plant	mi/trip	44
Mass	BDT/truck	14
Forest Material (chipped)	Btu/BDT, LHV	8500
Diesel	Btu/gal LHV	128000
	lb/gal	7.14
	kg/gal	3.24

REFERENCES

1. Costs and Benefits of Biomass-to-Ethanol Production Industry in California, ADL report to the California Energy Commission, March 2001

COMMENTS

1. One way distance is the average travel for a plant with biomass available within a 50 mile radius
Reference 1 estimated costs at $9-19/BDT ($50-55 per hour of travel)

Other Studies, MTE		
GREET, LHV	308,400	gal diesel/BDT

APPENDIX Module T15 Power Transmission

		Units	LHV, GJ	GJ/GJ, primary fuel
INPUTS TO MODULE				
Input Fuel				
Electriciy	1.0000	kWh	0.004	1.053
Other Inputs				
Total				
OUTPUTS FROM MODULE				
Primary Products:				
Electricity	0.9500	kWh	0.003	1.000
Secondary Products				
None				
Total				
Module Thermal Efficiency				95.00%

INPUT PARAMETERS		
Conversion	GJ/kWh	0.0036

APPENDIX Module T16 LPG Transport, Truck

		Units	LHV, GJ	GJ/GJprimary product delivered
INPUTS TO MODULE				
Input Fuel				
LPG	7,800	gal	691	1.000
Other Inputs				
Diesel	20.00	gal (round trip)	3	0.004
Total				1.004

OUTPUTS FROM MODULE				
Primary Products:				
LPG	7,800	gal	691	1.000
Secondary Products				
Total				1.000
Module Efficiency, GJ-output/GJ-input				99.6%

INPUT PARAMETERS		
Average Truck Fuel Usage	mi/gal	5
Average One-way Trip Distance	mi	50
LPG	Btu/gal LHV	84000
Diesel	Btu/gal LHV	128000
	lb/gal	7.14
	kg/gal	3.24

REFERENCES	
1. Evaluation of Fuel-Cycle Emissions on a REactivity Basis, Vol. 1, Main Report, Sep 1996 Prepared for CARB by Acurex Environmental	
Other Studies, MTE	
GREET, LHV	98.5%

APPENDIX Module T17 LNG Transport, Truck

		Units	LHV, GJ	GJ/GJprimary product delivered
INPUTS TO MODULE				
Input Fuel				
LNG	7,800	gal	600	1.000
Other Inputs				
Diesel	20.00	gal (round trip)	3	0.005
Total				1.005

OUTPUTS FROM MODULE				
Primary Products:				
LNG	7,800	gal	600	1.000
Secondary Products				
Total				1.000
Module Efficiency, GJ-output/GJ-input				99.6%

INPUT PARAMETERS		
Average Truck Fuel Usage	mi/gal	5
Average One-way Trip Distance	mi	50
LNG	Btu/gal LHV	72900
Diesel	Btu/gal LHV	128000
	lb/gal	7.14
	kg/gal	3.24

REFERENCES	
1. Evaluation of Fuel-Cycle Emissions on a REactivity Basis, Vol. 1, Main Report, Sep 1996 Prepared for CARB by Acurex Environmental	
Other Studies, MTE	
GREET, LHV	98.5%

APPENDIX Module T18 FTD Transport, Truck

		Units	LHV, GJ	GJ/GJprimary product delivered
INPUTS TO MODULE				
Input Fuel				
FTD	7,800	gal	978	1.000
Other Inputs				
Diesel	20.00	gal (round trip)	3	0.003
Total				1.003

OUTPUTS FROM MODULE				
Primary Products:				
FTD	7,800	gal	978	1.000
Secondary Products				
Total				1.000
Module Efficiency, GJ-output/GJ-input				99.7%

INPUT PARAMETERS		
Average Truck Fuel Usage	mi/gal	5
Average One-way Trip Distance	mi	50
FTD	Btu/gal LHV	118800
Diesel	Btu/gal LHV	128000
	lb/gal	7.14
	kg/gal	3.24

REFERENCES	
1. Evaluation of Fuel-Cycle Emissions on a REactivity Basis, Vol. 1, Main Report, Sep 1996 Prepared for CARB by Acurex Environmental	
Other Studies, MTE	
GREET, LHV	98.5%

APPENDIX Module T19 Biodiesel Transport, Truck

		Units	LHV, GJ	GJ/GJprimary product delivered
INPUTS TO MODULE				
Input Fuel				
Biodiesel	7,800	gal	964	1.000
Other Inputs				
Diesel	20.00	gal (round trip)	3	0.003
Total				1.003

OUTPUTS FROM MODULE				
Primary Products:				
Biodiesel	7,800	gal	964	1.000
Secondary Products				
Total				1.000
Module Efficiency, GJ-output/GJ-input				99.7%

INPUT PARAMETERS		
Average Truck Fuel Usage	mi/gal	5
Average One-way Trip Distance	mi	50
Biodiesel	Btu/gal LHV	117090
Diesel	Btu/gal LHV	128000
	lb/gal	7.14
	kg/gal	3.24

REFERENCES	
1. Evaluation of Fuel-Cycle Emissions on a REactivity Basis, Vol. 1, Main Report, Sep 1996 Prepared for CARB by Acurex Environmental	
Other Studies, MTE	
GREET, LHV	98.5%

APPENDIX Module T20 FTD Transport, Marine

		Units	LHV, GJ	GJ/GJprimary product delivered
INPUTS TO MODULE				
Input Fuel				
FTD	142,500	DWT	5,558,380	1.0000
Other Inputs				
Bunker Fuel	3,847,500	kg	163,785	0.0295
		(round trip)		
Diesel	2,243	gal	303	0.0001
		(In-port)		
Total				1.0295

OUTPUTS FROM MODULE				
Primary Products:				
FTD	142,500	DWT	5,558,380	1.0000
Secondary Products				
None				
Total				1.0000
Module Efficiency, GJ-output/GJ-input				97.13%

INPUT PARAMETERS		
Bunker Fuel		
Tanker Fuel Consumption	kg/ton-mi	0.0018
Average One-way Trip Distance	mi	7500
Bunker Fuel	Btu/kg	40350
Tanker Load Efficiency		0.95
Diesel		
In-port use factor	kg/DWT	0.051
Energy Content	Btu/gal, LHV	128000
Diesel Density	kg/gal	3.24
FTD		
	Btu/gal LHV	118800
	lb/gal	6.43
	gal/DWT	311
	kg/gal	2.915

REFERENCES

1. Evaluation of Fuel-Cycle Emissions on a REactivity Basis, Vol. 1, Main Report, Sep 1996
Prepared for CARB by Acurex Environemntal

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Appendix B. Spill Liability

Section 1002 of the Oil Pollution Act of 1990 (OPA) holds facilities that cause oil spills responsible for cleanup costs and damages resulting from the spill. The law limits the liability of an onshore facility owner/operator to $350 million per spill unless the oil spill resulted from gross negligence, willful misconduct, or a violation of federal regulations. In these cases liability is unlimited. The unlimited liability provision also applies to the owner/operator in cases where the negligence, misconduct, or violation results from a responsible party's agent, employee, or person contracting with the owner/operator.

A responsible party can absolve their liability for the response costs and damages of an oil spill if the spill results from an act of God, an act of war, or an act or omission of a third party. In these cases, the facility owner or operator is released from the strict liability provisions. In the event that the responsible party either is not known or is absolved of their liability, the OPA established the Oil Spill Liability Trust Fund to help pay for cleanup costs, oil spill damages, and certain operational expenses incurred as a result of an oil spill response. In addition to the liability provisions, facility owners and operators that discharge oil also may be subject to administrative or judicial penalties.

B.1 Oil Spill Liability Trust Fund

Under the Oil Pollution Act of 1990, the owner or operator of a facility from which oil is discharged (also known as the responsible Party) is liable for the costs associated with the containment or cleanup of the spill and any damages resulting from the spill. The EPA's first priority is to ensure that responsible parties pay to clean up their own oil releases. However, when the responsible party is unknown or refuses to pay, funds from the Oil Spill Liability Trust Fund can be used to cover removal costs or damages resulting from discharges of oil.

The primary source of revenue for the fund is a five-cents per barrel fee on imported and domestic oil. Collection of this fee ceased on December 31, 1994 due to a "sunset" provision in the law. Other revenue sources for the fund include interest on the fund, cost recovery from the parties responsible for the spills, and any fines or civil penalties collected. The Fund is administered by the U.S. Coast Guard's National Pollution Funds Center (NPFC).

The Fund can provide up to $1 billion for any one oil pollution incident, including up to $500 million for the initiation of natural resource damage assessments and claims in connection with any single incident. The main uses of Fund expenditures are:

- State access for removal actions
- Payments to Federal, state, and Indian tribe trustees to carry out natural resource damage assessments and restorations
- Payment of claims for uncompensated removal costs and damages
- Research and development and other specific appropriations

B.2 Penalties Under the Law

Under the Clean Water Act, as amended by the Oil Pollution Act of 1990, EPA has greater authority to pursue administrative, judicial, and criminal penalties for violations of the regulations and for discharges of oil and hazardous substances. Under the new penalty system, three different courses of action are available to EPA in the event of a spill: (1) EPA may assess an administrative penalty against the facility; (2) EPA may seek a judicial penalty against the facility in the federal court system; or (3) EPA may seek a criminal action against the facility in the federal court system.

B.3 Administrative Penalties

EPA may assess administrative penalties against oil or hazardous substance dischargers as well as facility owners or operators who fail to comply with the Oil Pollution Prevention regulation. The administrative penalty amounts that violators must pay have increased under the OPA, and a new system of administrative penalties was created based on two classes of violations. Class I violations may be assessed an administrative penalty up to $10,000 per violation, but no more than $25,000 total. The more serious Class II violations may be assessed up to $10,000 per day, but no more than $125,000 total. However, a facility that has been assessed a Class II administrative penalty cannot be subject to a civil judicial action for the same violation.

B.3.1 Judicial Penalties

Judicial penalties may be assessed against facility owners or operators who discharge oil or hazardous substances, who fail to properly carry out a cleanup ordered by EPA, or who fail to comply with the oil pollution prevention regulation. Courts may assess judicial penalties for discharges as high as $25,000 per day or up to $1,000 per barrel of oil spilled (or $1,000 per reportable quantity of hazardous substance discharged.) For those discharges that result from gross negligence or willful misconduct, the penalties increase to no less than $100,000 and up to $3,000 per barrel of oil spilled (or per unit of reportable quantity of hazardous substance discharged). Owners and operators of facilities that fail to comply with an EPA removal order may be subject to civil judicial penalties up to $25,000 per day, or three times the cost incurred by the Oil Spill Liability Trust Fund, as a result of their failure to comply. Finally, if the facility fails to comply with its EPA-approved SPCC plan, the civil judicial penalty may reach $25,000 per day of violation.

B.3.2 Criminal Penalties

EPA may pursue criminal penalties against facility owners or operators who fail to notify the appropriate Federal Agency of a discharge of oil. Specifically, under the Clean Water Act, the federal government can impose a penalty up to a maximum of $250,000 for an individual or $500,000 for a corporation, and a maximum prison sentence of five years.

(Source: www.epa.gov)

Appendix C. Overview of Scenarios for GE Model

The general equilibrium (GE) model predicts future economic activity, based on shifts in expenditures and revenue. The implications of these changes in economic activity are based on data collected for a known year, often referred to as the model's "base" year. As a result, the GE model is calibrated for a particular base year, with any future scenarios described, relative to that frame of reference.

Each scenario is built around two basic elements: 1) gasoline displacement from improved light-duty vehicle fuel economy, and 2) diesel displacement from gas-to-liquid (GTL) fuels. While each scenario is constructed petroleum fuel displacement, emission control devices are also considered in this analysis, consistent with ARB's PZEV regulations. The economic implications for each of these features are captured in terms of household/consumer expenditures and resulting changes in industrial/sector revenue, and entered into the model.

C.1 Scenario Description

The four scenarios chosen for the general equilibrium model span a range of potential petroleum reductions, with Scenario 1 representing modest fuel savings and Scenario 4 the largest decreases in fuel use. The elements of each scenario are outlined in Table 1, below.

Scenario 1: Captures modest fuel savings from technologies that are easiest to implement, based on cost-effectiveness and technical viability, consistent with projections provided by K.G. Duleep/EEA. Diesel displacement from GTL and PZEV costs are also included.

Scenario 2: Describes a situation with larger assumed petroleum displacements than those found in Scenario 1. Gasoline fuel savings are based on ACEEE-Advanced technology, with higher costs and fuel economy levels. Diesel displacement from GTL and PZEV costs are also included.

Scenario 3: Projects increased petroleum reductions from Scenario 2, based on ACEEE-Moderate technology and hydrogen Fuel Cell Vehicles (FCVs). Starting in 2020, FCV populations are chosen to maintain total light-duty gasoline use at 2002 levels. Diesel displacement from GTL and PZEV costs are also included.

Scenario 4: Depicts largest petroleum reductions, consistent with ACEEE-Full Hybrid technology. Diesel displacement from GTL and PZEV costs are also included.

GTL fuels were included in all four scenarios because they offer significant (approximately 1 billion gallons annually beginning in 2020) petroleum reduction, at minimal cost to consumer.

The gasoline fuel consumption for each scenario is shown in Figure C-1.

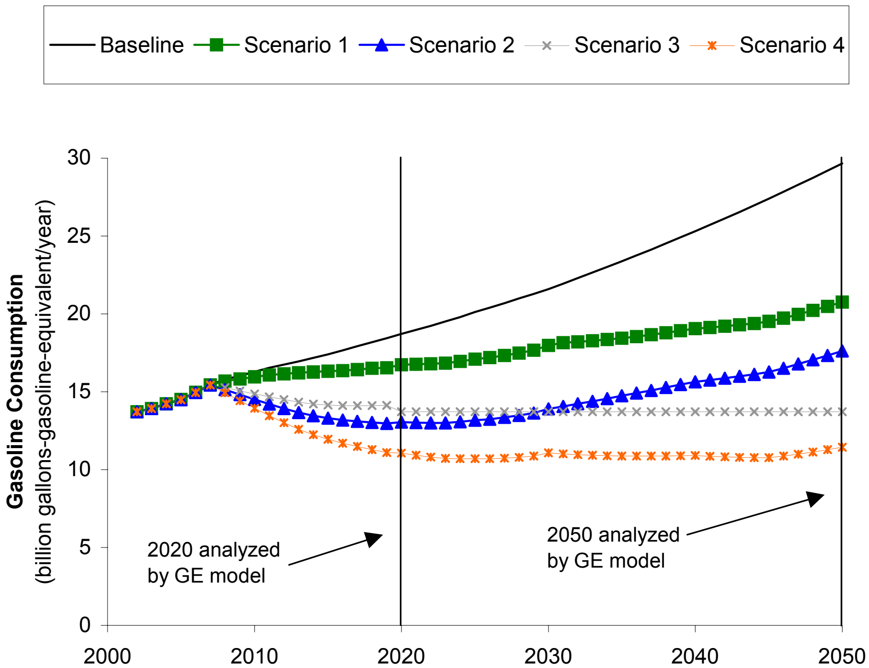

Figure C-1. Projected gasoline use by light-duty vehicles

Figure C-2 shows the projected diesel fuel demand with FTD added as a blend stock. The penetration scenario is shown as a step change in 2008, which is probably unrealistic. Additional time would be required to fully introduce FTD as a blend stock to all California diesel.

Figure C-3 show the combined gasoline and diesel (expressed as gasoline equivalent gallon) demand for the four scenarios. The scenarios shown on this figure are a combinatio of the gasoline and diesel results shown in Figure C-1 and C-2.

C.2 Magnitude of Economic Impacts

The shifts in economic activities, detailed at the sector level, are shown in Table C-1 through C-4. Just as with petroleum reduction, the scenarios span a range of economic impacts. For 2020, Scenario 1 shows a total shift of $5.351 billion ($2.087 billion costs + $3.264 billion), while Scenario 4 shows a shift of $26.193 billion ($13.660 billion costs + $12.553 billion benefits). While these impacts are large in magnitude, recall that in 2002, the California economy is approximately $1 trillion. With even a modest annual growth of 0.5%, the state economy would be $1.1 trillion in 2020, implying that the largest values associated with Scenario 4 would result in a total impact of no more than 2.5%.

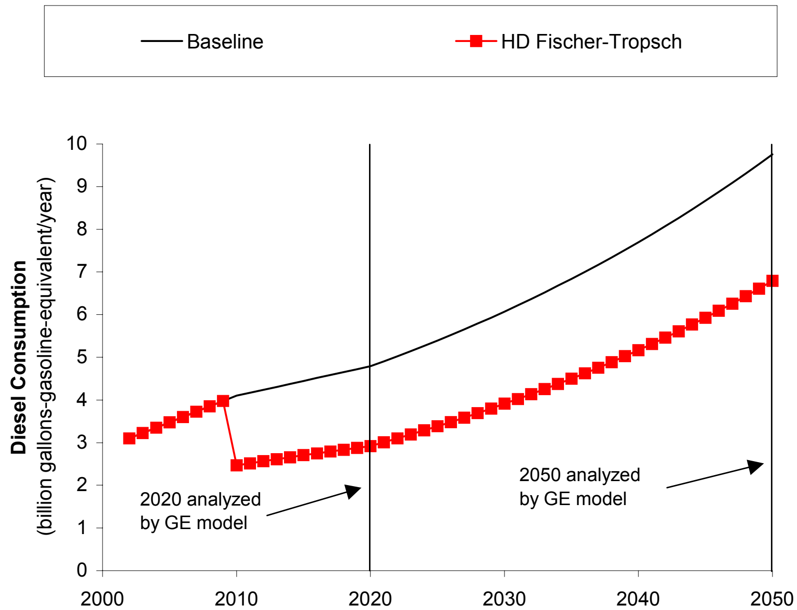

Figure C-2. Projected Diesel Fuel Demand with FTD

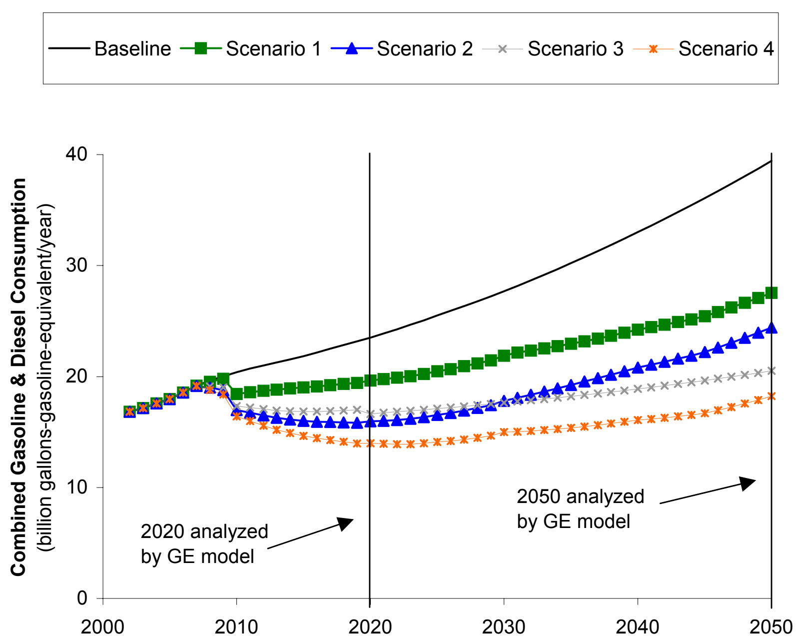

Figure C-3. Combined Gasoline and Diesel Demand for the Four Scenarios

Table C-1. Economic Impacts for Scenario 1

Scenario 1: EEA/Duleep Fuel Economy Improvements					
Changes in Consumer Expenditures	2020 million 2002$	2050 million 2002$	Changes in Sector Revenue	2020 million 2002$	2050 million 2002$
Cost			Benefit		
Household (inc. Vehicle Cost)	1,460	4,900	Vehicle Manuf. (inc. vehicle revenue)	1,460	4,900
Household (inc. PZEV Cost)	501	812	Vehicle Manuf. (inc. PZEV revenue)	501	812
Commercial (inc. GTL-diesel cost)	125	146	Foreign GTL Producer (inc. revenue)	125	146
Total Costs	2,087	5,858	Total Benefits	2,087	5,858
Benefit			Cost		
Household (dec. gasoline expenditure)	3,264	14,617	Refiners (decrease in revenue)	2,547	11,409
			California Excise Tax (dec. revenue)	358	1,604
			Federal Excise Tax (dec. revenue)	358	1,604
Total Benefits	3,264	14,617	Total Costs	3,264	14,617

Table C-2: Economic Impacts for Scenario 2

Scenario 2: ACEEE-Advanced Fuel Economy Improvements					
Changes in Consumer Expenditures	2020 million 2002$	2050 million 2002$	Changes in Sector Revenue	2020 million 2002$	2050 million 2002$
Cost			Benefit		
Household (inc. Vehicle Cost)	4,197	6,794	Vehicle Manuf. (inc. vehicle revenue)	4,197	6,794
Household (inc. PZEV Cost)	501	812	Vehicle Manuf. (inc. PZEV revenue)	501	812
Commercial (inc. GTL-diesel cost)	125	146	Foreign GTL Producer (inc. revenue)	125	146
Total Costs	4,824	7,752	Total Benefits	4,824	7,752
Benefit			Cost		
Household (dec. gasoline expenditure)	9,284	19,746	Refiners (decrease in revenue)	7,246	15,411
			California Excise Tax (dec. revenue)	1,019	2,167
			Federal Excise Tax (dec. revenue)	1,019	2,167
Total Benefits	9,284	19,746	Total Costs	9,284	19,746

Table C-3: Economic Impacts for Scenario 3

Scenario 3: ACEEE-Moderate + Fuel Cell Vehicles (reducing fuel use to 2002 levels)					
Changes in Consumer Expenditures	2020 million 2002$	2050 million 2002$	Changes in Sector Revenue	2020 million 2002$	2050 million 2002$
Cost			Benefit		
Household (inc. Vehicle Cost)	5,680	10,463	Vehicle Manuf. (inc. vehicle revenue)	5,680	10,463
Household (inc. FCV cost)	945	1,133	Vehicle Manuf. (inc. FCV revenue)	945	1,133
Household (inc. PZEV Cost)	443	322	Vehicle Manuf. (inc. PZEV revenue)	443	322
Commercial (inc. GTL-diesel cost)	125	146	Foreign GTL Producer (inc. revenue)	125	146
Household (inc. H2 cost)	776	8,718	Hydrogen Industry (inc. revenue)	673	7,609
			California Excise Tax (inc. H2 revenue	52	554
			Federal Excise Tax (inc. H2 revenue)	52	554
Total Costs	7,970	20,782	Total Benefits	7,970	20,782
Benefit			Cost		
Household (dec. gasoline expenditure)	8,269	26,170	Refiners (decrease in revenue)	6,454	20,425
			California Excise Tax (dec. gas. rev)	908	2,872
			Federal Excise Tax (dec. gas. rev)	908	2,872
Total Benefits	8,269	26,170	Total Costs	8,269	26,170

Table C-4: Economic Impacts for Scenario 4

Scenario 4: ACEEE-Full Hybrid Vehicles					
Changes in Consumer Expenditures	2020 million 2002$	2050 million 2002$	Changes in Sector Revenue	2020 million 2002$	2050 million 2002$
Cost			Benefit		
Consumer (inc. Vehicle Cost)	13,033	21,096	Vehicle Manuf. (inc. vehicle revenue)	13,033	21,096
Consumer (inc. PZEV Cost)	501	812	Vehicle Manuf. (inc. PZEV revenue)	501	812
Commercial (inc. GTL-diesel cost)	125	146	Foreign GTL Producer (inc. revenue)	125	146
Total Costs	13,660	22,054	Total Benefits	13,660	22,054
Benefit			Cost		
Consumer (dec. gasoline expenditure)	12,533	29,896	Refiners (decrease in revenue)	9,782	23,333
			California Excise Tax (dec. revenue)	1,376	3,281
			Federal Excise Tax (dec. revenue)	1,376	3,281
Total Benefits	12,533	29,896	Total Costs	12,533	29,896

The values listed here are only meant to frame the total volume of economic activity associated with each scenario. Please note that term “impact” is intentionally vague implying neither “net” benefit or penalty to the economy; this discussion only frames the input to the GE model, and its results. Whether or not these impacts result in negative or positive contributions to the economy will be determined by the GE model, and described elsewhere.